Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.39, 114]

Question(s):

Please provide Concentric's views on the impact to business and financial risk, ROE methodology peer groups, capital structure, and any other aspect of cost of capital, of electricity distributors, electricity transmitters, and OPG's regulated business, of:

a) Utilities being eligible for various green and sustainable bond frameworks.

b) Utilities being considered attractive investments to meet various ESG, and/or sustainable investing goals.

Response:

a) Utilities' risks, financial performance and business operations are not meaningfully altered by the issuance of green bonds. While they signal a utility's commitment to ESG or sustainable principles and may enhance investor interest in the issuer's debt, there has not been a significant difference in interest rates between green and conventional bonds, and companies' use of proceeds from green bonds must meet eligibility criteria and may require increased reporting and transparency on their use. Utilities' fundamental creditworthiness (credit rating), deemed debt ratios and ROEs as authorized by the OEB are not altered by issuing green bonds in place of conventional bonds.

b) It is not accurate that investors identify the utility industry as a wholly ESG or sustainable investment. Contrarily, ESG or sustainable investors selectively provide capital to utilities that demonstrate business changes supportive of the Energy Transition. For example, Raymond James' fixed asset management firm, Eagle Fixed Income, has noted that "As the investor community pursues a greener economy, how can we justify our ESG investment thesis in utility offerings?... we invest in them to become part of incremental changes."[1] The firm notes that "Eagle

[1] Eagle Asset Management, "ESG-Focused Investing in U.S. Electric Utilities," August 2023.

Fixed Income evaluates the ESG performance of electric utility companies from the perspectives of low carbon transition, generation fuel mix, and resiliency.” [2]

Utilities’ efforts to meet jurisdictional and internal ESG-related goals carry increased business and financial risk. The transition away from traditional fuels increases business risk in the form of stranded assets, adapting new methodologies into existing infrastructure, first-of-a-kind construction, fuel sufficiency and increased necessity for resilience. From a financial risk perspective, increased capital spending strains cash flows and credit metrics and increases the risk of unrecoverable costs. Utilities operating in supportive regulatory environments in which they can fully and timely recover their costs and provide reasonable and competitive returns to investors will be in position to attract capital from ESG and/or sustainability-focused investors.

For utility sector-specific risks, please refer to the response provided in N-M2-10-SEC-33.

[2] Ibid.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.30]

Question(s):

Concentric states: “A demonstration that the regulated utility has actually earned its allowed return is a retrospective view of a constructive regulatory environment and a well-functioning utility, but not a measure of the business risk and financing requirements companies face in the future and not the basis on which prospective investors make investment decisions.” Does Concentric believe the inverse is also correct, that a demonstration that a regulatory utility has not earned its allowed return is not a measure of the business and business risk, and financing requirements companies face in the future and not the basis on which prospective investors make investment decisions?

Response:

The inability to earn the authorized ROE can be an indication of regulatory lag, and often indicates that the utility does not have adjustment clauses that enable it to timely recover its prudently incurred costs. But, as with a utility that earns more than its allowed ROE, the inability to earn the authorized in the past is not necessarily a measure of whether the utility will be able to do so in the future. The answer really depends on what is expected to change in the future. For example, if a utility has under-earned for the past five years, then it is likely that investors would probe to understand the cause and make a judgment as to whether it will continue to fail to earn its authorized ROE, and its impacts on earnings and cash flow. However, if a utility has consistently over-earned its authorized ROE but faces new risks such as energy transition, then an investor is likely to question whether the regulatory environment will evolve in a way that allows the utility to continue earning its authorized ROE.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.44]

Question(s):

With respect to Figure 3, please provide the revised 5-year Bloomberg Beta (raw and adjusted) that separates Canadian and US utilities.

Response:

Please see N-M2-10-SEC-44, Attachment 1. Please also see Figure 16 of Concentric's report, Exhibit M2, which details average Value Line and Bloomberg (adjusted) betas for May 2024 for each proxy group (Canadian, U.S. Electric, U.S. Gas, North American Electric, North American Gas, and North American Combined).

Average Betas **Proxy Group**	*May 2024* **5-Year Bloomberg Beta (raw)**	*May 2024* **5-Year Bloomberg Beta (adjusted)**
Canadian	0.77	0.85
U.S. Electric	0.87	0.91
U.S. Gas	0.84	0.89
North American Electric	0.82	0.88
North American Gas	0.80	0.87
North American Combined	0.82	0.88

CANADIAN PROXY GROUP

Company Name	Ticker	At May 2024 5-year Bloomberg Beta (raw)	At May 2024 5-year Bloomberg Beta (adjusted)
AltaGas Limited	ALA	1.23	1.16
Canadian Utilities Limited	CU	0.79	0.86
Emera Inc.	EMA	0.58	0.72
Enbridge Inc.	ENB	0.90	0.93
Fortis, Inc.	FTS	0.58	0.72
Hydro One, Ltd.	H	0.54	0.69
AVERAGE		**0.77**	**0.85**

U.S. ELECTRIC PROXY GROUP

Company Name	Ticker	At May 2024 5-year Bloomberg Beta (raw)	At May 2024 5-year Bloomberg Beta (adjusted)
Alliant Energy Corporation	LNT	0.81	0.87
Ameren Corporation	AEE	0.76	0.84
American Electric Power Company, Inc.	AEP	0.77	0.84
Duke Energy Corporation	DUK	0.74	0.82
Entergy Corporation	ETR	0.96	0.97
Eversource Energy	ES	0.85	0.90
Exelon Corporation	EXC	0.97	0.98
Evergy, Inc.	EVRG	0.84	0.89
NextEra Energy, Inc.	NEE	0.87	0.91
OGE Energy Corporation	OGE	1.03	1.02
Pinnacle West Capital Corporation	PNW	0.90	0.94
PPL Corporation	PPL	1.10	1.07
Portland General Electric Company	POR	0.82	0.88
Southern Company	SO	0.85	0.90
Xcel Energy Inc.	XEL	0.74	0.83
AVERAGE		**0.87**	**0.91**

U.S. GAS PROXY GROUP

Company Name	Ticker	At May 2024 5-year Bloomberg Beta (raw)	At May 2024 5-year Bloomberg Beta (adjusted)
Atmos Energy Corp.	ATO	0.74	0.83
Northwest Natural Gas Company	NWN	0.62	0.74
ONE Gas, Inc.	OGS	0.75	0.83
Spire, Inc.	SR	0.80	0.86
AVERAGE		**0.84**	**0.89**

NORTH AMERICAN ELECTRIC GROUP		At May 2024	At May 2024
Company Name	**Ticker**	**5-year Bloomberg Beta (raw)**	**5-year Bloomberg Beta (adjusted)**
Canadian Utilities Limited	CU	0.79	0.86
Emera Inc.	EMA	0.58	0.72
Fortis, Inc.	FTS	0.58	0.72
Hydro One, Ltd.	H	0.54	0.69
Alliant Energy Corporation	LNT	0.81	0.87
Ameren Corporation	AEE	0.76	0.84
American Electric Power Company, Inc.	AEP	0.77	0.84
Duke Energy Corporation	DUK	0.74	0.82
Entergy Corporation	ETR	0.96	0.97
Eversource Energy	ES	0.85	0.90
Exelon Corporation	EXC	0.97	0.98
Evergy, Inc.	EVRG	0.84	0.89
NextEra Energy, Inc.	NEE	0.87	0.91
OGE Energy Corporation	OGE	1.03	1.02
Pinnacle West Capital Corporation	PNW	0.90	0.94
PPL Corporation	PPL	1.10	1.07
Portland General Electric Company	POR	0.82	0.88
Southern Company	SO	0.85	0.90
Xcel Energy Inc.	XEL	0.74	0.83
AVERAGE		**0.82**	**0.88**

NORTH AMERICAN GAS GROUP		At May 2024	At May 2024
Company Name	**Ticker**	**5-year Bloomberg Beta (raw)**	**5-year Bloomberg Beta (adjusted)**
AltaGas Limited	ALA	1.23	1.16
Canadian Utilities Limited	CU	0.79	0.86
Enbridge Inc.	ENB	0.90	0.93
Fortis, Inc.	FTS	0.58	0.72
Atmos Energy Corp.	ATO	0.74	0.83
Northwest Natural Gas Company	NWN	0.62	0.74
ONE Gas, Inc.	OGS	0.75	0.83
Spire, Inc.	SR	0.80	0.86
AVERAGE		**0.80**	**0.87**

NORTH AMERICAN COMBINED PROXY GROUP		At May 2024	At May 2024

Company	Ticker	5-year Bloomberg Beta (raw)	5-year Bloomberg Beta (adjusted)
AltaGas Limited	ALA	1.23	1.16
Canadian Utilities Limited	CU	0.79	0.86
Emera Inc.	EMA	0.58	0.72
Enbridge Inc.	ENB	0.90	0.93
Fortis, Inc.	FTS	0.58	0.72
Hydro One, Ltd.	H	0.54	0.69
Alliant Energy Corporation	LNT	0.81	0.87
Ameren Corporation	AEE	0.76	0.84
American Electric Power Company, Inc.	AEP	0.77	0.84
Duke Energy Corporation	DUK	0.74	0.82
Entergy Corporation	ETR	0.96	0.97
Eversource Energy	ES	0.85	0.90
Exelon Corporation	EXC	0.97	0.98
Evergy, Inc.	EVRG	0.84	0.89
NextEra Energy, Inc.	NEE	0.87	0.91
OGE Energy Corporation	OGE	1.03	1.02
Pinnacle West Capital Corporation	PNW	0.90	0.94
PPL Corporation	PPL	1.10	1.07
Portland General Electric Company	POR	0.82	0.88
Southern Company	SO	0.85	0.90
Xcel Energy Inc.	XEL	0.74	0.83
Atmos Energy Corp.	ATO	0.74	0.83
Northwest Natural Gas Company	NWN	0.62	0.74
ONE Gas, Inc.	OGS	0.75	0.83
Spire, Inc.	SR	0.80	0.86
AVERAGE		**0.82**	**0.88**

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.49]

Question(s):

For each utility in the North American Electric Proxy Group, please provide: a) its credit ratings, b) its most recent credit rating report from each of S&P, DBRS, and Moody's, and c) a breakdown of annual revenue by business type (electricity distribution, electricity transmission, electricity generation, regulated natural gas, and other).

Response:

Please see N-M2-10-SEC-45, Attachment 1 and N-M2-10-SEC-45, Attachment 2 (Confidential) for the requested information.

Company	Ticker	S&P Credit Rating	Regulated Revenue / Total Revenue	Regulated Electric Revenue / Total Reg. Revenue
Canadian Utilities Limited	CU	NR	84.77%	n/a
Emera Inc.	EMA	BBB	98.03%	n/a
Fortis Inc.	FTS	A-	98.96%	n/a
Hydro One Limited	H	A-	99.42%	n/a
Alliant Energy Corporation	LNT	A-	97.76%	84.69%
Ameren Corporation	AEE	BBB+	100.00%	87.40%
American Electric Power Company, Inc.	AEP	BBB+	96.65%	100.00%
Duke Energy Corporation	DUK	BBB+	100.09%	91.28%
Entergy Corporation	ETR	BBB+	96.84%	98.45%
Eversource Energy	ES	A-	100.00%	81.89%
Exelon Corporation	EXC	BBB+	100.00%	90.90%
Evergy, Inc.	EVRG	BBB+	100.00%	100.00%
NextEra Energy, Inc.	NEE	A-	76.80%	100.00%
OGE Energy Corporation	OGE	BBB+	100.00%	100.00%
Pinnacle West Capital Corporation	PNW	BBB+	100.00%	100.00%
Portland General Electric Company	POR	BBB+	100.00%	100.00%
PPL Corporation	PPL	A-	99.85%	93.54%
Southern Company	SO	A-	90.74%	78.71%
Xcel Energy Inc.	XEL	BBB+	99.29%	81.65%

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Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.50]

Question(s):

For each utility in the North American Gas Proxy Group, please provide: a) its credit ratings, b) its most recent credit rating report from each of S&P, DBRS, and Moody's, and c) a breakdown of annual revenue by business type (electricity distribution, electricity transmission, electricity generation, regulated natural gas, and other).

Response:

Please see N-M2-10-SEC-46, Attachment 1 and N-M2-10-SEC-46, Attachment 2 (Confidential) for the requested information.

Company	Ticker	S&P Credit Rating	Regulated Revenue / Total Revenue	Regulated Gas Revenue / Total Revenue
AltaGas Limited	ALA	BBB-	36.57%	n/a
Canadian Utilities Limited	CU	NR	84.77%	n/a
Enbridge Inc.	ENB	BBB+	12.30%	n/a
Fortis Inc.	FTS	A-	98.96%	n/a
Atmos Energy Corporation	ATO	A-	100.00%	95.61%
Northwest Natural Gas Company	NWN	A	97.51%	95.08%
ONE Gas, Inc.	OGS	A-	100.00%	100.00%
Spire, Inc.	SR	BBB+	91.82%	91.82%

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Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.80]

Question(s):

With respect to Figure 27: Comparison of North American Authorized Equity Returns:

a) For each of the Canadian ‘Operating Utility’, please provide a copy of the regulatory decision(s) that last affirmed the existing ROE and/or equity thickness and last adjusted the ROE and equity thickness.

b) For the ‘U.S. Electric Mean’ and ‘U.S. Gas Mean’, please provide the underlying data and calculations used to determine the mean ROE and equity thickness. For each utility part of the calculation, please provide a copy of the regulatory decision(s) that last affirmed the existing ROE and/or equity thickness and last adjusted the ROE and equity thickness.

Response:

a) Please see SEC-47(a), Attachments 1 – 6 for the requested decisions.

b) Please see SEC-47(b), CONFIDENTIAL Attachment 1 for the requested information. The regulatory decisions are a matter of public record and may be found on the websites of the Commissions and Boards using the docket number or case number.

Please note that Regulatory Research Associates (RRA) data provided in Attachment 1 is confidential under Concentric’s subscription agreement with S&P Capital IQ Pro.

DECISION

QUEBEC **ENERGY REGION**

D-2022-119	R-4156-2021 Phase 2	October 26, 2022

PRESENT:

Jocelin Dumas

Lise Duquette
Esther Falardeau

Managers

Energize, dry
Gazifere Inc.

Intragas, dry

Plaintiffs

and

Speakers whose names appear below

Decision on the merits

Joint request relating to the fixing of rates of return and capital structures

Plaintiffs:

Énergir, sec (Énergir)
represented by Me Éric Bédard, Me Marie-Pier Cloutier and Me Patrick Ouellet;

Gazifère Inc. (Gazifère)
represented by Me Adina Georgescu;

Intragaz, dry (Intragaz)
represented by Me Adina Georgescu.

Speakers:

Association of Industrial Gas Consumers (ACIG)
represented by Me Paule Hamelin;

Association Hôtellerie Québec and Association Restauration Québec (AHQ-ARQ) represented by Me Steve Cadrin;

Canadian Federation of Independent Business (CFIB)
represented by Me André Turmel;

Option consommateurs
(OC) represented by Me Éric McDevitt David.

TABLE OF CONTENTS

1. INTRODUCTION

[1] On April 16, 2021, Énergir, Gazifère and Intragaz (the Plaintiffs) filed with the Régie de l'énergie (the Régie), pursuant to sections 32, 48, 49 (3) and 51 of the *Act respecting the Régie Energy*[1] (the Act), a joint application relating to the fixing of rates of return and capital structures[2] .

[2] This request follows decisions D-2020-1453 and D-2020-1044 where the Régie noted a context of low risk-free interest rates showing no sign of recovery. Rather, the filing of the application and its processing took place against the backdrop of financial market turbulence, the pandemic, international geopolitical tensions and a recent significant increase in interest rates.

[3] In this request, the Claimants propose that two aspects, namely the authorization to proceed jointly and the authorization to incur expenses, together with the creation of deferred expense accounts (CFR), be treated in a phase 1 The filing of the Plaintiffs' evidence and the merit review on the rates of return and capital structures applicable to each of the Plaintiffs would be dealt with in a second phase.

[4] On June 30, 2021, the Régie rendered its decision D-2021-0835 on the recognition of the interveners, the authorization to proceed jointly with the application relating to the fixing of rates of return and capital structures and the authorization to incur expenses, together with the creation of CFR.

[5] Between November 5 and 8, 2021, the Claimants filed a joint application in the context of phase 2 of this case[6] .

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1 CQLR, c. R-6.01.
2 Exhibit B-0002.
3 File R-4119-2020, decision D-2020-145, p. 92, para. 377.
4 File R-4122-2020 Phase 1A, decision D-2020-104, p. 22, par.72.
5 Decision D-2021-083.
6 Exhibit B-0011.

[6] On January 25, 2022, the Régie rendered its decision D-2022-0067 in the context of phase 2, relating to the subjects of intervention, the processing of requests for recognition of expert status, participation budgets , ACIG's request for a $140,000 advance for expert fees and the schedule for reviewing the file.

[7] On February 7, 2022, the Claimants filed additional evidence.

[8] Between February 24 and March 1 , 2022, the Régie and the interveners filed their Request for Information (RFI) No. 1 with the Plaintiffs. On March 23, 2022, the Claimants filed their responses to these RFIs.

[9] Between March 25 and 29, 2022, ACIG and AHQ-ARQ filed a challenge to certain of the Claimants' responses to their RFI.

[10] On April 5, 2022, the Régie rendered its decision D-2022-0468 on the challenges relating to certain responses of the Claimants to the RFIs of the ACIG and the AHQ-ARQ.

[11] On May 12, 2022, ACIG filed an application for recognition of expert witness status for Dr. Laurence Booth and Dr. Asa S. Hopkins.

[12] On May 13, 2022, the Claimants filed an application for recognition of expert witness status for Dr. Bente Villadsen and Dr. Toby Brown9 .

[13] On May 20, 2022, the Claimants challenged ACIG's application for recognition of expert witness status for Dr. Hopkins10.

[14] On June 10, 2022, the Claimants filed an amended claim (the Claim)11.

7 Decision D-2022-006.
8 Decision D-2022-046.
9 Exhibit B-0309.
10 Exhibit B-0320.
11 Exhibit B-0331.

[15] From June 12 to 20, 2022, the Régie is holding a hearing on phase 2 of this case. During this hearing, on June 16, 2022, the Régie renders its decision on applications for recognition of expert status. Thus, it recognizes the expert status of:

- Dr. Asa S. Hopkins as: “ *expert on energy transition in the gas industry, and business risk* ”;
- Dr. Laurence Booth as “ *expert on rate of return, capital structure and business risk* »[12];
- Dr. Toby Brown as an expert in the assessment of business risks of regulated utilities for purposes of determining rate of return and capital structure;
- Dr. Bente Villadsen as an expert in determining the rate of return and capital structure of regulated utilities.

[16] On July 5, 2022, the Régie specifies and sets the deadlines for the filing of the written arguments of the Claimants and interveners as well as for the filing of the written replies of the Claimants.

[17] On July 19, 2022, the Claimants filed their reply, the date on which the Régie began its deliberation.

[18] In this decision, the Régie rules on the Application as well as on the application for a confidentiality order.

[12] Exhibit A-0062, p. 11.

2. MAIN FINDINGS OF THE GOVERNMENT

[19] The Régie determines a rate of return of 8.9% on Énergir's equity for application to the 2022-2023 rate year, beginning October 1 , 2022. It also approves a deemed capital structure of Énergir is made up of 38.5% equity, 7.5% preferred shares and 54% debt.

[20] The Régie determined that Intragaz's rate of return on equity (TRCP) will be linked to that of Énergir over the period from May 1 , 2023 to April 30, 2033, such that their rate of return on " *the 'equity* ' is equivalent depending on their own capital structure. It approves a deemed capital structure of Intragaz consisting of 46% equity and 54% debt.

[21] Finally, the Régie determines a rate of return of 9.05% on Gazifère's equity for application to the 2023 rate year, beginning on January 1 , 2023. It also approves a deemed capital structure of Gazifère made up of 40% equity and 60% debt.

3. LEGAL FRAMEWORK...

[22] Following RFI No. 3 from the Régie13, the Claimants filed the Application14 for the Régie to determine their rate of return and approve their capital structure:

> APPROVE a *rate of return of 10% on Énergir's equity, all in accordance with Dr. Villadsen's recommendations (Exhibit B-0015, ÉGI-1), for application to the 2022 rate year -2023, beginning October 1, 2022;*

> *APPROVE a deemed capital structure of Énergir consisting of 43% equity and 57% debt;*

---

[13] Room B-0330, p. 1.
[14] Exhibit B-0331.

APPROVE a rate of return of 10% on Gazifère's equity, all in accordance with Dr. Villadsen's recommendations (Exhibit B-0015, ÉGI-1), for application to the 2023 rate year, starting January 1, 2023;

APPROVE a deemed capital structure of Gazifère consisting of 45% equity and 55% debt;

APPROVE a rate of return of 10% on Intragaz's equity, all in accordance with Dr. Villadsen's recommendations (Exhibit B-0015, ÉGI-1), for application to the 2023 to 2032 rate period , beginning May 1, 2023;

APPROVE a deemed capital structure of Intragaz consisting of 43% equity and 57% debt;

[…] ”15.

[23] Various provisions of the Act govern the Régie's exercise of setting a rate of return.

[24] Thus, under section 49 of the Act, when the Régie sets a natural gas rate, the latter must be “ *just and reasonable* ” (section 49 (1) (7o)). The rate it sets must allow for a reasonable return on the rate base (section 49 (1) (3o) of the Act). In addition, the Régie must carry out this exercise while ensuring compliance with the financial ratios (section 49 (1) (5o) of the Act). The Act does not provide that the rate of return must be “ *just and reasonable* ”. Rather, the Act provides that the rate set by the Régie must “ *allow a reasonable return on the rate base* ”.

[25] Thus, for each of the Plaintiffs, under section 51 of the Act, the tariffs must not provide for higher rates or more onerous conditions than necessary to allow, in particular, to cover capital and operating costs, to maintain the stability of the distributor and the normal development of its distribution network or to ensure a reasonable return on the rate base.

15 Room B-0331, p. 7.

[26] In its decision D-2009-156[16], the Régie specified its role and its powers when it sets a rate of return for a distributor. To this end, she reviewed the case law framing the concept of a reasonable rate of return, in particular through the *Bluefield*[17] and *Hope*[18] decisions of the American Supreme Court. Through this review, the Régie noted, among other things, that a public service company is not only entitled to revenues allowing it to cover its operating costs, but also to sufficient revenues to cover its capital cost. She also noted that it is the result of the regulatory exercise that must be fair and reasonable and not the method used to achieve it, as mentioned in *Hope :*

> " [184] *The legal principles framing the concept of a reasonable rate of return were first set out in two landmark US Supreme Court decisions, Bluefield and Hope. The first of these two decisions sets out the standard by which the reasonableness of a tariff is judged:*
>
> > *"A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties . A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions g*
> > [footnotes omitted]

16 File R-3690-2009, decision D-2009-156, p. 44 to 50.

17 *Bluefield Water Works & Improvement Co.* v. *Public Service Commission of West Virginia* 262 US 679 (1923).

18 *Federal Power Commission* v. *Hope Natural Gas Company* 320 US 591 (1944).

[27] With respect to the rights of a public utility company to revenues to enable it to cover not only its operating costs, but also its cost of capital, the *Hope* decision supplemented the standard at this regard :

> " *The ratemaking process under the Act, ie, the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the Natural Gas Pipeline Co. case that "regulation does not assure that the business shall produce net revenues" […]. But, such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. […] By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. […]* ". [footnote omitted]

[28] Finally, as mentioned above, *Hope* specifies that it is the result of the regulatory exercise that must be fair and reasonable, and not the method used to achieve it:

> " *… We held in Federal Power Commission v. Natural Gas Pipeline Co. […], that the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function, moreover, involves the making of "pragmatic adjustments". And when the Commission's order is challenged in the courts, the question is whether that order, "viewed in its entirety," meets the requirements of the Act. Under the statutory standard of "just and reasonable," it is the result reached, not the method employed, which is controlling. […] It is not theory, but the impact of the rate order, which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Act is at an end. The fact that the method employed to reach that result may contain infirmities is not then important. Moreover, the Commission's order does not become suspect by reason of the fact that it is challenged. It is the product of expert judgment which carries a presumption of validity. And he who would upset the rate order under the Act carries the heavy burden of making a convincing showing that it is invalid because it is unjust and unreasonable in its consequences. […]* ". [footnote omitted]

[29] A review of the relevant case law also revealed three criteria that have historically been recognized by regulators as the basis for establishing the standard of reasonable return, namely the criteria of comparable investment, integrity finance and attracting capital.

[30] Thus, to be reasonable, a rate of return on capital must meet the following three criteria:

- be comparable to that which the capital invested in another company presenting a similar risk would yield (comparable investment criterion);

- allow the company to attract additional capital on favorable terms reasonable (criterion of the capital attraction effect);

- allow the regulated company to preserve its financial integrity (criterion financial integrity).

[31] In its decision D-2009-156[19], the Régie concluded that there is consensus on these criteria and that they can serve as a guide in the exercise of its jurisdiction with regard to setting a reasonable rate of return.

[32] Moreover, in this same decision, the Régie considered that its duty was to determine a reasonable rate of return and that the method it used for this purpose fell within its discretion. In this regard, the Régie pointed out that the courts have recognized the wide latitude and discretion of regulatory bodies in the choice of method to set a reasonable rate of return on shareholder equity.

[19] File R-3690-2009, decision D-2009-156.

[33] In its decision D-2014-034, the Régie noted the three criteria set out above, but added that it must also take into consideration certain principles for evaluating reasonable performance, including that of the independence of the regulated company *(stand alone),* the principle of opportunity cost, as well as the consideration of several valuation methods and models20.

[34] The Régie would also like to provide certain clarifications in connection with the criterion of financial integrity. In follow-up to Dr. Villadsen's responses to her RFI # 1, Dr. Booth asks Dr. Villadsen for a supplement in response to the following RFI:

> “ *3.2 Please indicate any statements that Dr. Villadsen is aware of from previous Régie decisions that the Régie targets a particular bond rating* ”21.

[35] To this question, Dr. Villadsen replies that she is of the opinion that financial integrity implies an “A” credit rating for a Canadian regulated entity:

> “ *Answer: Dr. Villadsen is not aware of any previous Régie decisions that target a specific credit rating. However, Dr. Villadsen is aware that in D-2009-156, paragraph 173, the Régie stated that the return must enable the regulated company to preserve its financial integrity. It is Dr. Villadsen's view that this means an A range rating for a Canadian regulated utility. An A range target is ideal because it gives the regulated entity some headroom to maintain investment-grade metrics if cash flows or debt levels deviate in the near-term. Setting a target lower than the A range for a Quebec utility (for example, BBB range) risks the company's ability to maintain its financial integrity. Simply put, a lower range gives the Canadian utility less headroom and risks the company falling into sub-investment grade territory if cash flows or debt levels deviate from expectations* ”22. [emphasis added]

[36] However, in its decision D-2009-156, the Régie indicated that the rate of return should allow the regulated company to maintain its financial integrity, but that this financial integrity did not imply an “A” rating for a regulated company. Rather, it found that the "A" rating, confirmed by reports from credit agencies and a stable outlook, did not lead to the conclusion that Gaz Métro's financial integrity would have been called into question because of fixed rates of return using the

20 File R-3842-2013, decision D-2014-034, p. 7 and 8.

21 Room B-0193, p. 4.

22 Room B-0193, p. 4.

automatic adjustment formula:

> " [207] *The Régie notes that the spreads between the yield of long-term government bonds and that of bonds rated "A", or that of comparable regulated companies, subsequently widened at the end of 2008 and in beginning of 2009 an unprecedented expansion for a brief period.*
> *As mentioned by all the experts heard in this dossier, the North American and global economies then went through a period of uncertainty and high volatility, a crisis of a magnitude that no expert or estimation model could have predict in advance. Nevertheless, the evidence indicates that the distributor should be able to fully realize the return of 8.76% granted by the Régie, for the fiscal year ending September 30, 2009.*
>
> *[208] <u>On the other hand, the Régie's reading of the credit agency reports, which confirm Gaz Métro's "A" rating and a "stable" outlook, does not allow it to conclude that Gaz Métro's financial integrity Metro would have been called into question because of the rates of return determined using the</u> FAA. Market access capital for Gaz Métro remains reasonable, as evidenced by the two debt issues made in October 2008 and June 2009. It is worth noting that despite the uncertainty prevailing in the first half of 2009, the interest rate on bonds 10 years, issued by Gaz Métro last June, was similar and even lower than that at which these bonds were trading in June 2007 and June 2008* ”23.
>
> [emphasis added] [footnotes omitted]

[37] Thus, the Régie is of the opinion that compliance with the financial integrity criterion does not necessarily imply maintaining an “A” rating.

Impacts on tariffs and consumers' ability to pay

[38] The Régie also wondered, in this decision D-2009-156, whether the exercise of determining a reasonable return should involve the repercussions that such a return could have on rates, to which she replied in the negative.

[39] Indeed, the Régie pointed out that when it exercises its functions, it must ensure the reconciliation between the public interest, the protection of consumers and a

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23 File R-3690-2009, decision D-2009-156, p. 53, para. 207 and 208.

fair treatment of the distributor24. She stated:

> “ [191] […] *However, this cannot deprive investors of the reasonable return they are entitled to expect under section 49.3, the two sections of the Act being in no way incompatible.*
>
> *[192] Indeed, the return granted to the shareholder constitutes one of the elements of the distributor's cost of service, just like its operating costs. The tariff established by the Régie must, by virtue of the Act and case law, allow sufficient revenue to cover all of these costs. Moreover, the three criteria mentioned above make no reference to users' ability to pay. However, by referring to the returns obtained in the rest of the economy, the rate granted takes into account the limits that market forces necessarily impose on the returns on equity that can be obtained in other sectors of activity of comparable risk. to that of the distributors* ”25.
>
> [footnote omitted]

[40] The Régie then concluded that the users' ability to pay should not intervene in its decision on the quantum of what constitutes a reasonable return for the shareholder. It also pointed out that under section 51 of the Act, the rate set cannot provide for higher rates than those required to achieve this reasonable return, which adequately ensures the protection of consumer interests.

[41] Finally, the Régie indicated that, as mentioned in *Hope,* " *it is the result of the regulatory exercise that must meet the standard of reasonable return and not the method* "26 and that in this regard , US courts have recognized the wide latitude and discretion of regulators in determining the best method to set a reasonable return on rate base.

24 Art. 5 of the Act.

25 File R-3690-2009, decision D-2009-156, p. 49, para. 191 and 192.

26 File R-3690-2009, decision D-2009-156, p. 49, para. 194.

4. HIGHLIGHTS OF THE POSITION OF THE EXPERTS OF THE APPLICANTS AND INTERVENERS

[42] The purpose of Énergir, Intragaz and Gazifère's Application is to present a proposal to adjust their presumed capital structure as well as the TRCP to a level comparable to that of companies with similar risks. In support of their Application, the Plaintiffs file the testimonies of Dr. Brown and Dr. Villadsen as well as the report of the firm Aviseo Conseil (the Aviseo Report) on the evolution of the business risks of gas distributors in the establishment of the rate of reasonable return.

[43] This Request comes against a backdrop of financial market turbulence, a pandemic, international geopolitical tensions and a recent significant increase in interest rates.

[44] The Claimants submit that they are faced with new challenges that have an impact on investors' perceptions, including a significant acceleration in the implementation of public and environmental policies aimed at meeting the growing need for an energy transition. in the face of the climate crisis.

[45] They also submit that in this context, the Régie, under section 5 of the Act, must, in particular, in the exercise of its functions, ensure compliance with the objectives of the government's energy policies.

[46] In order to perform a comparative analysis of their risks with those of their industry peers, the Plaintiffs called on Dr. Brown and Dr. Villadsen, of the firm *The Brattle Group* (Brattle) as experts .

[47] According to Dr. Villadsen, the replacement of preferred shares in Énergir's presumed capital structure by equity and debt is necessary. Similarly, it proposes an increase in the TRCP from 8.9% to 10% in order to respect the criteria of comparable investment, capital attraction and financial integrity.

[27] Room B-0028, p. 4.

[48] The Plaintiffs' business risks are assessed by Dr. Brown using the facts and information presented in the Aviseo Report. The expert also uses Dr. Villadsen's reference sample of American gas distributors28.

[49] Dr. Villadsen, relying on Dr. Brown's report, indicating that Intragaz's risks are similar to those of Énergir, recommends for Intragaz a capital structure and a TRCP identical to those of Énergir. Furthermore, as Intragaz's tariffs have a duration of application of 10 years, it also recommends a maturity premium of 50 basis points on the TRCP of this company.

[50] Finally, Dr. Villadsen recommends, for Gazifère, a TRCP identical to that of Énergir and Intragaz. It incorporates Dr. Brown's conclusion that Gazifère's risks are greater than those of Énergir, by proposing that its presumed capital structure includes a greater share of equity than Énergir.

[51] Dr. Villadsen estimates the cost of capital of comparable companies using the Financial Asset Pricing Model (FAEM), the Empirical Financial Asset Pricing Model (MEÉAF) and the Discounting Model. cash flows (AFM).

[52] The parameters used in these models come from samples of Canadian and American companies whose capital structures are valued at market. The expert also uses classic techniques in finance to take into account the disparity in debt levels between the companies in the samples and those of the Claimants (CMPCAI and Hamada's equations29).

[53] Dr. Villadsen's final recommendations are based primarily on the TRCP ranges obtained using the MEÉAF adjusted according to Hamada's equations,
as well as their impact on the Plaintiffs' financial ratios in order to maintain or achieve an "A" quality credit rating.

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28 Room B-0027, p. 2.

29 After-tax Weighted *Average Cost of Capital* (ATWACC). Room B-0015, p. 112 to 117.

[54] ACIG, for its part, retained the services of Dr. Hopkins to act as an expert witness on the question of business risks, as well as those of Dr. Booth as an expert on the questions of capital structure, rate of return and business risk.

[55] IGUA and the other intervenors, AHQ-ARQ, CFIB and OC, endorse the conclusions of Dr. Hopkins' report, as well as those of Dr. Booth with respect to capital structure and rate of return. With regard to business risks and, more specifically, the Aviseo Report, the stakeholders have coordinated to limit the duplication in their interventions.

[56] In his expert report and his analysis, Dr. Booth uses the MEAF to estimate the fair and reasonable rate of return for the Plaintiffs, insofar as the risks of Énergir and Intragaz are similar and those of Gazifère are slightly higher than those of Énergir.

[57] It validates the estimate obtained using an AFM model whose parameters are valued from the Canadian market and not from any particular security or sample of securities.

[58] With respect to business risks, Drs. Hopkins and Booth submit that the analyzes filed by the Claimants are incomplete and do not justify the upward adjustments they are requesting to their capital structure and their TRCP. The experts propose a complete review of these risks in three years, including in particular the question of the impacts of climate change on their business model.

[59] In addition, taking into account their ability to realize their authorized return on a regular basis and the low volatility of their realized return, Dr. Hopkins considers that Énergir and Gazifère have a lower level of risk than the gas distributors Americans included in Dr. Villadsen's sample.

[60] In light of Dr. Hopkins' risk findings, Dr. Booth recommends maintaining the Claimants' current capital structures as he believes that their risks remain similar to what they were since their last rate setting. yield.

[61] The expert also recommends that the Régie reject the method of evaluating the cost of capital using the WACCAI used by Dr. Villadsen. Dr. Booth submits

that the use of capital structures at their market value is incompatible with a regulated business, since this concept requires retaining the principle of maximizing value for shareholders rather than that of setting fair and reasonable rates.

[62] With respect to the Hamada adjustments, Dr. Booth is of the opinion that it is a methodology similar to that of WACCAI using market value weightings to subsequently adjust everything according to weightings of book values.

[63] The expert suggests a TRCP of 7.50% on Énergir and Intragaz equity and 7.65% on Gazifère equity.

5. BUSINESS RISKS......

5.1 POSITION OF THE PLAINTIFFS

5.1.1 EVOLUTION OF BUSINESS RISK

[64] The Plaintiffs filed the Aviseo Report30 in evidence.

[65] For each of the Plaintiffs, the firm Aviseo Conseil (Aviseo) carried out a specific analysis in Quebec relating to the evolution of business risks for the period 2021-2030 compared to the decade 2010-2020. The table below presents this assessment for each of the five business risk categories.

30 Exhibit B-0028.

TABLE 1

AVISEO REPORT : RISK EVOLUTION MATRIX FOR THE PERIOD 2021-2030
COMPARED TO THE 2010-2020 DECADE
FOR ENERGY, GAS AND INTRAGAS

Risks	**Energize**	**Gasiferous**	**Intragas**
Environmental policies and public policies	Rising Rising		Rising
Composition of the clientele	Rising Rising		Similar
Energy context	Rising Rising		Rising
Cut	Similar	Rising	Similar
business partner	Rising Rising		Similar

Source: Exhibit B-0028, p. 38.

[66] Based on its analysis of the business risk evolution matrix, Aviseo's main finding is that public and environmental policies lead to greater risks and uncertainties for the 2021-2030 period than they were not during the previous decade31.

[67] During the hearing, speaking on behalf of the Plaintiffs, Mr. Éric Lachance, President and Chief Executive Officer of Énergir, argued that the issues related to climate change and, in particular, decarbonization, are known and are therefore not new. He specifies that the new element lies in the collective will to accelerate the pace of change32.

[68] Based on the business risks identified in the Aviseo Report, Dr. Brown conducted a comparative assessment of the Plaintiffs' business risk by considering five categories of risk: i) demand, ii) competition, iii) operations, iv) regulations, and v) procurement.

[69] Dr. Brown explains that in order to provide an adequate level of compensation to shareholders of regulated companies, depending on the risk associated with their

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31 Room B-0028, p. 12.
32 Room A-0050, p. 14 and 15.

investment, the allowed return must reflect the business risk. Under the *fair return standard* , investors should expect to recover their investment and achieve a reasonable return33.

[70] Dr. Brown adds that business risk can manifest itself in an increase in the volatility of returns expected for investors as well as in the possibility that the capital invested cannot be recovered over its lifespan. This possibility is also called "capital recovery risk "34. The expert explains that the assessment of business risk, carried out at a specific time, is of a prospective nature (" *forward looking* ")35.

[71] Dr. Brown indicates that he examined the individual business risk of each of the Plaintiffs. He compared the Plaintiffs' risks to those of the sample of natural gas distribution companies located in the United States drawn up by Dr. Villadsen36. However, he specifies that he did not examine in this case the evolution of the Claimants' risk37.

[72] The expert considers that, compared to the level of risk observed since the last complete examination of the Plaintiffs' rate of return on equity, a period of three to five years does not constitute a relevant horizon for assessing the risk of capital recovery. The relevant valuation period should reflect the useful life of the assets38.

[73] Furthermore, in response to an RFI39 from the Régie, Dr. Brown reiterates that investors care about the future and not the past, so historical returns can only be relevant to the extent that they provide indications for the future.

33 Room B-0027, p. 4.
34 Room B-0027, p. 7 and 8.
35 Room B-0344, p. 4.
36 Room B-0027, p. 10.
37 Room B-0141, p. 3, R1.1.
38 Room B-0141, p. 4, R1.3.
39 Room B-0342, p. 4, R1.3.

[74] In his testimony, Dr. Brown explained that he was not informed of any reason whatsoever to expect a systematic difference between the performance authorized by the Régie and the performance achieved by the Plaintiffs40.

[75] In argument41, the Claimants reiterated that the rates of return achieved in the past do not constitute a relevant element to be considered in the assessment of business risk in order to establish a reasonable rate of return on the capital invested, which the latter being established on a prospective basis. Therefore, the past not being a guarantee of the future, the analysis must look to the future to assess the business risk.

[76] In addition, during this argument, the Claimants specify that they are not subject to any legal or regulatory obligation relating to the development or submission of a business plan, as suggested by the interveners' expert. . They specify that such a request would impose an additional burden in relation to that provided for in the current regulatory framework42.

Evolution of the business risk for each plaintiff

[77] Based on the risk factors used in the Aviseo Report, the evolution of business risk differs for each of the Claimants.

5.1.1.1 Evolution of Énergir's business risk

[78] At the hearing, Mr. Jean-François Tremblay, testifying as Senior Director, Regulation at Énergir, specified that the measures put in place by the Plaintiffs, such as the supply of dual energy and renewable natural gas, will not not entirely eliminate the business risks related to the energy transition that the Claimants face, particularly in a context where the regulatory environment is changing rapidly43.

[79] Thus, Mr. Tremblay specified that, according to the Aviseo Report, several risk factors will exert pressure on demand in the coming years. Considering

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40 Room B-0027, p. 6.
41 Room B-0388, p. 55 and 56.
42 Room B-0388, p. 65.
43 Exhibit A-0054, p. 25, 26 and 27.

carbon neutrality objectives and the fact that Énergir mainly distributes fossil energy, it is committed to implementing decarbonization measures, including more specifically energy efficiency, dual energy and renewable natural gas. In this context, Énergir indicates that it is essential to succeed in the energy transition by maintaining the competitive position of natural gas, to ensure that the company's business model is resilient 44. Mr. Tremblay nevertheless specifies that by 2050, depending on the assumptions made, the company succeeds in preserving its competitive position, but barely manages to do so with the business model in place45.

5.1.1.2 Evolution of Gazifère's business risk

[80] In comparison with the 2010-2020 period, the Aviseo Report assesses that for 2021-2030, Gazifère's business risk is on the rise for all risk factors46.

[81] During the hearing, Mr. Jean-Benoit Trahan, President of Gazifère and Director of Operations Eastern Region of Enbridge, specified that, although certain initiatives such as RNG or dual energy aim to reduce the risks, these ci are increasing because these initiatives have not been commercially demonstrated at scale47. In addition, he specifies that Gazifère has implemented a long-term strategy that must be adapted according to the means at its disposal and according to the nature of the company's clientele.

[82] Gazifère also submits that the energy transition induces additional risks that the company did not have to manage before48.

[83] Finally, in the context of Hydro-Québec's competitive position, Gazifère recalls that the small size of the company always constitutes a significant risk.

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44 Exhibit A-0054, p. 102 and 103.
45 Exhibit A-0054, p. 106, and 107.
46 Room B-0388, p. 6.
47 Room A-0050, p. 55.
48 Room A-0050, p. 97.

5.1.2 COMPARATIVE RISK ASSESSMENT

[84] Dr. Brown identifies the additional factors of long-term uncertainty that the Plaintiffs face for the recovery of invested capital compared to all of the companies in the sample of American natural gas distributors from Dr. Villadsen. First, he mentions that the authorities have already implemented policies relating to greenhouse gas (GHG) emissions for the energy sector in Quebec and are considering adopting others. These policies have the effect of both increasing the price of natural gas and reducing demand for it, which means that the Plaintiffs' customers are more inclined to substitute natural gas for electricity. Second, Dr. Brown insists on the fact that electricity in Quebec is less expensive than in other jurisdictions. It also points out that the Claimants are relatively smaller in size than the other companies in the sample[49].

[85] Moreover, since Intragaz provides a storage service to Énergir, its only customer, Dr. Brown considers its business risk equivalent to that of the latter[50].

[86] Finally, Dr. Brown assesses that Gazifère's business risk is higher than that of Énergir and Intragaz[51]. Since Gazifère is a very small company and distributes mainly to residential customers, it faces a higher risk, particularly in the context of the conversion of a portion of its customers to electricity[52].
Consequently, the long-term uncertainty for capital recovery is greater for Gazifère than for Énergir[53].

[49] Room B-0027, p. 33.
[50] Room B-0344, p. 8.
[51] Room B-0344, p. 10.
[52] Room B-0027, p. 30.
[53] Room B-0027, p. 30.

5.1.3 CANADIAN REFERENCE GROUP

[87] In order to assess the Plaintiffs' business risk, Dr. Brown did not retain the Canadian reference group. Dr. Brown considers Dr. Villadsen's sample less relevant for comparison purposes and less representative in assessing the Plaintiffs' business risk. According to Dr. Brown, the sample of Canadian companies is heterogeneous in that most of the companies included in this sample are not concentrated in gas distribution.

5.1.4 US REFERENCE GROUP

[88] In his testimony, Dr. Brown explains that it is reasonable to compare risks between jurisdictions when the regulatory frameworks are similar[54].

[89] Dr. Brown notes that electricity represents strong competition for natural gas. In Quebec, the price of electricity for households is 50% to 80% cheaper than that prevailing in the United States. Although the number of Énergir customers remains stable, Dr. Brown qualifies the latter as a small natural gas distributor, characterized by a slower growth in its customer base compared to the companies of the American reference group[55].

[90] Finally, by comparing it to the companies in Dr. Villadsen's sample of American natural gas distributors, Dr. Brown assesses that the business risk range of Intragaz and Énergir is above of the average risk, whereas that of Gazifère is higher and is located towards the top of the range[56].

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[54] Room B-0027, p. 11.
[55] Room B-0344, p. 10.
[56] Room B-0344, p. 10.

5.2 POSITIONS OF INTERVENERS

[91] The interveners selected Dr. Hopkins and Dr. Booth as expert witnesses for the Plaintiffs' business risk assessment. For the purposes of this assessment, the experts take particular account of the comparison between the yields authorized and the yields achieved.

[92] The intervenors endorse the conclusions of Dr. Hopkins' report as well as those of Dr. Booth regarding business risks.

Business Risk Assessment - Dr. Hopkins

[93] Dr. Hopkins57 is of the view that short-term business risk is primarily operational in nature and arises from the fact that the business may realize less revenue than expected or face unexpected costs. This business risk is manifested by the variation in the return achieved by the company's shareholders.

[94] As for long-term business risk, he explains that natural gas distributors are mainly faced with the risk of not being able to recover the capital invested and of not realizing a return during the life of the capital invested58.

[95] Dr. Hopkins59 concludes that Énergir and Gazifère face a low level of short-term risk. This conclusion stems from their ability to realize the authorized return on a regular basis as well as the low volatility of their realized return compared to the companies in the sample of the American natural gas distributors of Dr. Villadsen.

[96] Furthermore, the expert is of the opinion60 that the evidence presented in the Aviseo Report and during Dr. Brown's testimony is insufficient to assess the long-term risk associated with stranded assets and electricity competition, including the risks associated with decarbonization resulting from the energy transition. Moreover, this evidence does not hold not sufficiently take into account the opportunities linked to decarbonisation or the impact of

[57] Part C-ACIG-0028, p. 5.
[58] Part C-ACIG-0028, p. 6.
[59] Part C-ACIG-0028, p. 3.
[60] Part C-ACIG-0028, p. 3 and 4.

risk mitigation measures of a prudently managed business to adapt to this transition.

[97] As for Intragaz, Dr. Hopkins submits that it faces little short-term and long-term business risk because it deals with a single client whose distribution activities are regulated and who will likely need his services for decades to come.

[98] Furthermore, and unlike Dr. Brown, Dr. Hopkins does not consider that the reductions in demand for the Plaintiffs' services expose them to a greater risk of capital recovery than the companies in the sample of American gas distributors. natural62.

[99] For Dr. Hopkins, a utility company that manages its activities prudently, so as to mitigate its business risks, should not be rewarded by being allowed a higher rate of return63.

[100] In order to mitigate long-term business risks, Dr. Hopkins is of the opinion that the Régie should establish the Plaintiffs' rates of return and capital structures on the basis of a business plan filed within three years. These business plans prepared by the Claimants should outline future risks and opportunities, as well as impacts and strategies to mitigate these risks64.

Business Risk Assessment - Dr. Booth

[101] As an indicator, by comparing the returns achieved with the authorized returns of Énergir and Gazifère since 199065, Dr. Booth concludes that neither of these two companies has had to face a business risk in the short term66.

[102] According to Dr. Booth, the term “long-term risk” is inappropriate, since the long term is simply the succession of short-term periods.

[61] Part C-ACIG-0028, p. 35.
[62] Part C-ACIG-0028, p. 21.
[63] Part C-ACIG-0028, p. 4.
[64] Part C-ACIG-0028, p. 21.
[65] Exhibit C-ACIG-0043, p. 25 and 26.
[66] Exhibit C-ACIG-0043, p. 26.

According to him, for long-term risk to manifest itself, a regulated company must be unable to realize its allowed return and rebalance its tariffs.

[103] Dr. Booth explained that a situation may arise where a utility suffers a loss of customers and the costs cannot be recovered from other rate classes because their rates would be too high. In such a situation, a " *death spiral* " could occur if the rate increases necessary to compensate for the revenue declines lead to an additional loss of customers. The company would therefore no longer be able to increase its rates sufficiently nor to achieve a fair return and even to achieve a sufficient return to recover its depreciation expenses67.

[104] However, until now the Plaintiffs have not incurred any problem having prevented them from realizing their authorized return. This situation is undeniable proof that there are very few long-term risks68.

[105] For Dr. Booth, on a prospective basis, it is important to examine supply and demand over the economic planning horizon in order to assess the risk associated with the costs stranded.

[106] According to the information in evidence69, natural gas production in Western Canada is not decreasing significantly. The only factor affecting the risk of stranded assets to consider is demand70.

[107] In order to assess the economic planning horizon that could apply to the Quebec natural gas distribution network, the expert Booth examined the situation of the natural gas transmission network supplying Quebec and the TransQuébec & Maritimes Inc. (TQM)71. It is based on a study on the natural gas transmission network supplying Quebec and the TQM network filed and approved by the Canada Energy Regulator in 2022 which concludes that there is no change in the economic planning horizon used to assess the depreciation of TQM's rate base assets in Quebec. Thus, the absence of modification of the amortization periods of the network

67 Exhibit C-ACIG-0043, p. 28.
68 Exhibit C-ACIG-0043, p. 28.
69 Exhibit C-ACIG-0043, p. 30.
70 Exhibit C-ACIG-0043, p. 31.
71 TQM's map shows that it supplies gas to the Énergir network in most of Quebec and the two networks are closely integrated. This is also why Énergir owns 50% of TQM and the remaining 50% is held by TransCanada (which became TC Energy in 2019). Source: Exhibit C-ACIG-0043, p. 33.

of TQM in Quebec leads the expert Booth to reject an increase in the risk for the demand for natural gas in Quebec supplied by the TQM network.

[108] For Dr. Booth, this conclusion means that the business risk assessment for the main natural gas pipeline supplying Quebec has remained unchanged and the business risks of Quebec gas distributors remain stable.

[109] Finally, with respect to the business risks arising from policies aimed at reducing GHG emissions and the risks associated with climate change, Dr. Booth indicates that climate change will constitute a risk factor if it affects
the Plaintiffs' ability to achieve their performance or whether they are dragging them into a " *death spiral* "72.

[110] Expert Booth sees only general statements in the evidence relating to the impact of climate change and the pressure exerted on customers to switch from natural gas to electricity. It also notes the absence of a complete plan showing the impact of these elements on the Claimants and supports the proposal of the
Dr. Hopkins to require the Claimants to submit a risk assessment plan and risk mitigation strategies73.

[111] Dr. Booth specifies that, given the regulatory framework in place, when these risks arise, they are entirely the responsibility of the clientele74. In order for these risks to be assumed by the shareholders, the regulatory authorities must decide in this direction.
In addition, the Plaintiffs must demonstrate not only that there is a decline in customers and a reallocation of volumes, but also that they are unable to cope with a decrease in the number of natural gas consumers in Quebec75 .

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72 Exhibit C-ACIG-0043, p. 34.
73 Exhibit C-ACIG-0043, p. 34.
74 Exhibit A-0062, p. 186.
75 Exhibit A-0062, p. 187.

5.2.1 EVOLUTION OF BUSINESS RISK

[112] Dr. Hopkins considers that Énergir's short-term business risk is lower today than it was in 2011[76]. He bases his assessment on the absence of evidence of risk over the long term, giving a significant weighting to short-term risks, and based on the expected filing of a request for a review of its rate of return in a few years.

[113] Dr. Hopkins believes that Gazifère's short-term business risk outlook has diminished since the last review in 2010. Furthermore, the evidence on Gazifère's long-term business risk does not support a conclusion that these risks have changed since 2010[77].

[114] According to him, Gazifère's long-term business risks are slightly higher than those of Énergir, since it serves relatively more buildings that are more likely to convert to electric power[78]. In addition, Gazifère's business context is such that it has fewer opportunities to mitigate its risks by serving industrial customers or customers for whom electrification is difficult.

[115] As for Intragaz, Dr. Hopkins[79] estimates that its business risk remains slightly lower than that of Énergir, just as it was in 2013. Although data showing the annual variability of returns is not available for During this 10-year period, the fact that the returns achieved by Intragaz were higher than the authorized returns demonstrates to investors that the risk is relatively low.
According to him, the Régie could take this performance into account as an element leading it to conclude that Intragaz faces fewer risks than when the Régie assessed them in 2013.

[76] Part C-ACIG-0048, p. 2, R1.1.
[77] Part C-ACIG-0048, p. 3, R1.1.
[78] Part C-ACIG-0028, p. 31.
[79] Part C-ACIG-0048, p. 4, R1.1.

5.2.2 COMPARATIVE RISK ASSESSMENT

[116] Based on the historical comparison between the returns achieved and the returns authorized since 1990, Dr. Booth notes that Énergir has achieved, with the exception of a single year over the entire period, a return annual at least equal to the authorized return. Over this entire period, Dr. Booth estimates that Énergir achieved an excess return of 0.58% on average[80]. Although this situation stems, at least in part, from the existence of a productivity incentive mechanism for setting rates, he believes that there is nothing to indicate that shareholders are at risk of not obtaining the authorized return. .

[117] According to Dr. Booth, the same is true for Gazifère, since since 1990 the company has achieved an excess return of 0.66% on average and has not been able to achieve its authorized return only five times. He is therefore of the opinion that the ability of the two companies to achieve their authorized return testifies to the absence of short-term risk[81].

[118] As for Intragaz, he recalls that in 2012, he indicated that the assets of the latter could not be distinguished from those of Énergir, a 50% shareholder of Intragaz. He reiterates this opinion. Consequently, Dr. Booth is of the opinion that Énergir's financial parameters should also apply to Intragaz[82].

5.2.3 CANADIAN REFERENCE GROUP

[119] With respect to regulated utilities in Canada, Dr. Booth explains that significant differences in business risk can be mitigated by regulatory authorities[83].

[120] Thus, according to Dr. Booth, the company with the lowest level of risk is the one that benefits from the best conditions and, therefore, has the least need for recourse to the protection of the regulatory regime. Conversely, a regulated business may face the same short-term risk in earning its income but have

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[80] Exhibit C-ACIG-0043, p. 25.
[81] Exhibit C-ACIG-0043, p. 26.
[82] Exhibit C-ACIG-0043, p. 27.
[83] Exhibit C-ACIG-0043, p. 20.

needs greater regulatory protection because its long-term risks are greater84.

[121] Thus, compared to other natural gas distribution companies in Canada, Dr. Booth considers that Énergir is one of the two regulated companies in the sample facing the highest level of business risk (" *the riskiest regulated utilities in Canada* ")85.

5.2.4 US REFERENCE GROUP

[122] Expert Hopkins concludes that the returns achieved by Énergir and Gazifère86 are higher than those achieved by the companies included in the sample of American natural gas distributors. The expert also notes that comparable companies generally do not achieve a return higher than their authorized return, unlike Énergir and Gazifère87.

[123] For Dr. Hopkins, in the presence of lower short-term risks, the authorized returns should be lower than those estimated by Dr. Villadsen for the sample of American natural gas distribution companies, because the short-term risk term is higher for the companies included in this sample than that of the Claimants88.

[124] Moreover, unlike Dr. Brown, Dr. Hopkins questions the relevance of the sample of American companies as a reference group in order to compare the risks of the Plaintiffs89. A benchmark group is used to provide an indication of the cost of capital of a prudently managed utility. To the extent that the companies in the sample of US companies do not take the measures available and expected by shareholders to mitigate the risks arising from climate policies, these companies do not constitute an appropriate reference group with a view to estimate the cost of capital of a prudently managed business. The cost of capital

[84] Exhibit C-ACIG-0043, p. 20.
[85] Exhibit C-ACIG-0043, p. 21.
[86] Part C-ACIG-0028, p. 15.
[87] Part C-ACIG-0028, p. 16.
[88] Part C-ACIG-0028, p. 16.
[89] Part C-ACIG-0028, p. 26.

calculated based on this benchmark group would be too high to be representative of a prudently managed company.

5.3 OPINION OF THE BOARD

Assessment of the Plaintiffs' business risks

[125] From the outset, the Régie notes that the Plaintiffs presented several elements of a qualitative rather than quantitative nature in support of the assessment of the factors having an impact on business risks. Among these elements, there is the ongoing energy transition and decarbonization efforts by 2030 that could affect the demand for fossil natural gas. In this regard, the Régie notes that pressure from society is prompting the Plaintiffs to accelerate the implementation of initiatives aimed at positioning the natural gas networks as part of the energy transition solution in order to secure their future90 .

[126] The Régie notes that these measures are put in place by the Plaintiffs in order to mitigate the risks they face and it understands that these initiatives have not yet been commercially demonstrated on a large scale.

[127] Based on these elements, the Régie cannot exclude from its considerations that the Plaintiffs' business context has evolved since the last review and that new elements are present.

[128] The Régie recognizes that the competitive position of natural gas, compared to electricity in Quebec, constitutes an inescapable element of the Plaintiffs' business risk and that the contemporary context of energy transition adds uncertainty to their business environment. 'business.

[129] However, despite this increased uncertainty which could ultimately lead to losses in the Plaintiffs' sales volume due to the energy transition, the Régie retains from the evidence that their competitive position has not deteriorated in the immediate term and believes that there is no indication of this in the foreseeable future either.

90 Room A-0050, p. 16.

[130] The Régie agrees with Dr. Booth's assessment that Énergir's business risk is higher than that of comparable Canadian natural gas distributors, mainly given the low price of electricity in Quebec. It also retains from Dr. Brown's assessment that Gazifère's business risk is higher than that of Énergir, due to a greater risk of its customers converting to electricity.

[131] Finally, the Régie considers, for the reasons expressed by Drs. Brown and Booth, that Intragaz's business risk is identical to that of Énergir, the latter being its only client for its storage services.

[132] The Régie thus concludes that the business risks of Énergir and Intragaz are comparable, whereas Gazifère presents a higher business risk than that of Énergir.

[133] **Thus, the Régie judges that the increased level of uncertainty in the business environment justifies an increase of 10 basis points from the top of the current range for Énergir's business risk adjustment, compared to the TRCP of a benchmark distributor. Consequently, the Régie determines that the new range for Énergir's business risk adjustment is 25 to 45 basis points rather than 25 to 35 basis points, as it was estimated in the last files on determining the rate of return on equity.**

[134] **Because it considers that Intragaz and Énergir face the same risk, the Régie determines that the range for Intragaz's business risk adjustment is also 25 to 45 basis points.**

[135] **The Régie considers that the higher business risk of Gazifère compared to that of Énergir justifies an adjustment of 15 additional basis points to the range established for Énergir. Consequently, the Régie sets the new range for Gazifère's business risk adjustment at 40 to 60 basis points rather than 25 to 50 basis points, as estimated at the last review.**

6. CAPITAL STRUCTURE AND RATE OF RETURN

6.1 POSITION OF THE PLAINTIFFS

[136] The Plaintiffs rely on the recommendations of their expert, Dr. Villadsen, to ask the Régie to review their capital structure and increase their TRCP91.

[137] Based on the analysis of the Plaintiffs' business risks carried out by Dr. Brown92, Dr. Villadsen recommends a TRCP of 10% for Énergir et Gazifère. In order to take into account Intragaz's 10-year tariff period, Dr. Villadsen recommends adding a premium of 50 basis points to Intragaz's rate of return for a TRCP of 10.5%. Alternatively, in accordance with a proposal from the expert, Intragaz is asking to link its rate of return to that of Énergir over the 2023-203293 horizon.

[138] Also, the expert recommends modulating the Plaintiffs' capital structure according to the differences in their business risks.

[139] Dr. Villadsen notes that Énergir's presumed capital structure includes 7.5% preferred shares, unlike its non-consolidated balance sheet, which does not. She also notes that the share of preferred shares is 3.4% higher than that of the companies in her Canadian sample. For this reason, it recommends the replacement of preferred shares in Énergir's deemed capital structure and proposes that it contain 43% equity and 57% debt.

[140] For Intragaz, the expert recommends that the presumed capital structure be identical to that of Énergir, namely 43% equity and 57% debt.

[141] According to Dr. Villadsen, in order to take into account the increased business risks of Gazifère compared to those of Énergir, she proposes a capital structure of Gazifère of 45% equity and 55% debt.

91 Room B-0331, p. 5, para. 34 to 38.
92 Room B-0027, p. 30, A48 and p. 32, A53.
93 Room B-0388, p. 92.

[142] The following table summarizes the current situation and the expert's recommendations.

TABLE 2

CURRENT SITUATION AND DEMAND ON CAPITAL STRUCTURE

ALLEGED AND TRCP

	Energize		**Intragas**		**Gasiferous**	
	Current	demand	Current	demand	Current	demand
Equity	38.5%	43%	46%	43%	40%	45%
Preferred shares	7.5%	0%	0%	0%	0%	0%
Debt	54%	57%	54%	57%	60%	55%
TRCP	8.9%	10%	8.5%	10% + 0.5%	9.1%	10%

Source: Table established using exhibit B-0015, p. 6, table 3 and p. 16, table 5.

[143] In order to estimate the returns demanded by investors, Dr. Villadsen and the Dr. Brown use recognized models in the fields of finance and regulations, such as the MEAF and the AFM. However, the use of these models requires parameters (examples: Beta94 and growth rate of dividends) whose sources come from companies traded on the stock exchange.

[144] In this context, Dr. Villadsen proposes the use of three distinct samples of companies traded on the stock exchange, namely Canadian gas holding companies, gas distributors and American water utilities95.

[145] Canadian gas holding companies and US gas distributors serve as comparable businesses to the Plaintiffs. The water utilities are used to validate the results of the models obtained using the data from the other two samples.

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94 The relationship between market risk and security risk is expressed by the Beta (or Beta) factor. See file R-3690-2009, decision D-2009-156, p. 59.

95 Room B-0015, p. 53, table 18 and p. 59, tables 20 and 21.

[146] Using the financial and stock market data of the companies in these samples, Dr. Villadsen obtains preliminary ranges for the Claimants' TRCP[96].
These ranges are preliminary since they do not include the expert's requirements with regard to the capital attraction and financial integrity criteria.

[147] Dr. Villadsen calculates these preliminary ranges using the MEAF, MEÉAF and AFM[97] models. The results of these models are then adjusted using methods to take account of financial leverage (effect of the disparity of the levels of indebtedness on the Betas or on the cost of capital[98]). In these calculations, the capital structure used to determine the debt levels of the companies in the samples is established according to their market value.

[148] Dr. Villadsen submits that compliance with the three criteria of reasonable return *(Fair Return Standard)* requires that the capital structure and the TRCP be determined in order to enable the Plaintiffs to achieve an "A" quality credit rating. Compliance with these three criteria also requires that the return, namely the TRCP multiplied by the share of equity in the capital structure, compares with that of companies deemed comparable to the Claimants[99].

[149] It is with this in mind that Dr. Villadsen proposes to set the level of equity and the TRCP of the Plaintiffs by ensuring that the previously calculated TRCP ranges comply with the financial ratios published by Dominion Bond Rating Service (DBRS). and Standard & Poor's (S&P) for Canadian and US utilities to maintain or obtain an "A" quality credit rating.

[96] Room B-0015, p. 75 and 76, A71. The data used by Dr. Villadsen is as of June 30, 2021.

[97] Financial Asset Pricing Model (MÉAF, in English CAPM), Empirical Financial Asset Pricing Model (MEÉAF, in English ECAPM) and Discounted Cash Flow Model (AFM, in English DCF).

[98] That is to say the " *Financial Risk Unlevered Method* " and Hamada's adjustments (with and without taxes). Refer to Exhibit B-0015, p. 18 to 21, A20 to A23, p. 65 and 66, A60 and p. 113 to 117.

[99] Room B-0015, p. 10 and 11, A11.

[150] According to Dr. Villadsen, the relevant financial ratios and their target are as follows:

EBIT Coverage[100] *:* at least 2.5 times;

FFO Interest Coverage[101] *:* 3.5 to 4.0 times, with a preference for high value fork;

FFO to Debt[102] *:* at least 15%.

[151] The expert examines various levels of equity in the assumed capital structure and the rates of return of each of the Claimants. Its final recommendation corresponds to the combination of these two components making it possible to meet the targets mentioned in the previous paragraph. In its calculations, two rates of return are considered, namely 9.25% and 10%. As these are within the preliminary TRCP ranges determined beforehand, the expert concludes that her final recommendation satisfies the three criteria of reasonable return.

[152] In response to an RFI from the Régie, Dr. Villadsen mentions that her recommendation with regard to the Plaintiffs' TRCP is slightly above the average of the results for Canadian gas holding companies and close to the average of the results for American gas distributors. The expert also mentions that the percentages of equity and the rates of return that she recommends are not adjusted upwards compared to those of the samples to take into account the risk of capital recovery, nor to take into account the risks attributable to GHG reduction initiatives[103].

[153] During the hearing, Dr. Villadsen updated certain parameters of the financial models she used, mainly a significant increase in the risk-free rate from 2.30% to 3.40% and a drop in the premium prospective risk ratio from 8.05% to 5.86%. These changes do not modify the expert's recommendation with regard to the TRCP of 10% for the Claimants[104].

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100 *Earnings before interest and taxes coverage: Earnings before interest and taxes coverage .*

101 *Funds from operations (FFO) to interest coverage:* Coverage of funds from operations on interest.

102 *Funds from operations (FFO) to Debt :* Ratio of funds from operations to debt.

103 Parts B-0143, p. 2, R1.1, and B-0141, p. 4, R1.4 and R1.5.

104 Room B-0350, p. 36 and 37.

Position of the ACIG expert

[154] Dr. Booth explains that in finance, risk is the probability of losing money and that, in the case of regulated utilities, this translates into the likelihood of not earning the allowed return105. There is a short-term risk, namely the risk that the public service realizes a return lower than its authorized return and a long-term risk (" *return on capital* "), namely that the public service does not recover a part of its capital invested in its rate base (" *return of capital* ").

[155] With regard to the short-term risk, the expert mentions that there is nothing to indicate that the Plaintiffs are having a problem achieving their authorized return. He also believes that the level of debt in their assumed capital structure does not cause any negative impact.

[156] Dr. Booth adds that TQM's most recent depreciation rates (2022) are based on economic lifespans up to 2050 for the service of the Énergir franchise and up to 2040 for the segment going in East Hereford. In addition, according to S&P106, Énergir Inc.'s business risk is "Excellent" and its financial risk is " Intermediate ".

[157] Thus, Dr. Booth considers that Énergir's short- and long-term business risks have not changed since their last review. The expert also notes that the equity in the deemed capital structures of the major gas distributors in Canada is between 36% and 38.5%.

[158] For these reasons, the expert recommends maintaining Énergir's presumed capital structure. He considers that Intragaz's risk is lower than that of Énergir, but since these two companies are integrated, there is, in his opinion, no disadvantage in establishing for Intragaz a capital structure and TRCP identical to those of 'Energize.

[159] The expert also recommends maintaining the presumed capital structure of Gazifère because it is a small gas distributor. However, he points out that

105 Exhibit A-0062, p. 200.
106 Exhibit cited on p. 14 of Exhibit C-ACIG-0087.

Altagas' capital structure is 39% equity. The latter is half the size of Gazifère and Altagas is not integrated into a major gas distributor.

[160] The following table presents the TRCP range according to the MEAF results calculated by Dr. Booth, for a generic gas distributor in Canada.

TABLE 3

TRCP RANGE ACCORDING TO **DR BOOTH 'S MEAF**

Factor		High	Down
Canada 30-Year Bond Yield Forecast		3.37	3.37
Adjustment to take into account the action of the Banque du Canada on long-term rates *(bond buying)107*		0.43	0.43
	(a)	3.80	3.80
Beta Factor		0.50	0.55
Market risk premium		x5.50 _	6.00
	(b)	2.75	3.30
Issuance costs	(c)	0.50	0.50
CAPM Result	= (a) + (b) + (c)	**7.05**	**7.60**

Source: Exhibit C-ACIG-0037, p. 67.

[161] In this MEAF, the risk-free rate, that is to say the forecast yield on 30-year Canada bonds according to the Parliamentary Budget Officer, is 3.37 %108. Added to this risk-free rate is 43 basis points, because the expert judges that in the absence of the measures to stimulate the economy adopted by the Bank of Canada *(quantitative easing* or *bond buying),* the return on 30-year Canada bonds would be at least 3.8%. This adjustment also takes into account the credit spread.
If Canada bond yields rise, then the credit spread should narrow.

107 Exhibit C-ACIG-0087, p. 24, Dr. Booth presents this adjustment on the line " *Adjustment for results of other models* ".

108 This is the yield on 10-year Canada bonds forecast by the *Parliamentary budget officer (Economic and Fiscal Outlook,* March 2022) for the years 2024–2026 (3.0%) to which the expert adds a spread for the rates at 10 years and at 30 years (0.37%).

[162] Furthermore, Dr. Booth proposes a formula under which the TRCP would be at least 7.5%. This TRCP would increase by 75 basis points for each 100 basis point increase in the risk-free rate above 3.8 %109. For example, if the risk-free rate increased from 3.8% to 4.25%, the TRCP would increase to 7.84 %110.

[163] According to Dr. Booth, the accumulation of savings by households during the pandemic and their high consumption mean that long-term rates of around 3% to 3.5% will be necessary. to counter inflation. This range is below the 3.8% threshold that the appraiser considers necessary before adjusting its TRCP upwards according to the recommended formula.

[164] Questioned at the hearing by the Régie, the expert submits that there is no stagflation in Canada and he believes that there will not be. The economy should instead grow faster than inflation in a context where he judges that the Bank of Canada will not have the necessary will to increase its key rate in order to counter inflation. He admits, however, that in the presence of stagflation, the cost of capital could increase rapidly111.

6.2 OPINION OF THE RÉGIE ON THE DEEMED CAPITAL STRUCTURE APPLICANTS

6.2.1 BOOK VALUE AND MARKET VALUE

[165] In her evidence and in response to RFIs112, Dr. Villadsen asserts that the Plaintiffs' presumed proportion of equity is lower than the proportion observed among the companies forming the samples of comparable companies, as shown in Table 4 She notes in particular that there would be almost 10 percentage points more equity among US gas distributors.

109 Exhibit C-ACIG-0061, p. 6, R2.1.
110 7.84 = 7.50 + 0.75 x (4.25 – 3.80).
111 Exhibit A-0063, p. 221 to 224.
112 Room B-0143, p. 28, R6.3.

TABLE **4**

FIGURE 7: AVERAGE CAPITAL STRUCTURES OF PROXY GROUP COMPANIES

Proxy Sample	DCF Capital Structure			3-Year Average Capital Structure		
	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio	Common Equity - Value Ratio	Preferred Equity - Value Ratio	Debt - Value Ratio
	[1]	[2]	[3]	[4]	[5]	[6]
Canadian Sample Average	48.8%	3.4%	47.8%	45.6%	4.4%	50.0%
U.S Natural Gas Sample Average	55.2%	1.2%	43.6%	61.1%	0.8%	38.1%
U.S Water Utility Sample Average	69.5%	0.0%	30.5%	70.8%	0.0%	29.2%

Sources and Notes:
[1], [4]:Workpaper #1 to Schedule No. BV-4.
[2], [5]:Workpaper #2 to Schedule No. BV-4.
[3], [6]:Workpaper #3 to Schedule No. BV-4.
Values in this table may not add up exactly to 1.0 because of rounding.

Source: Exhibit B-0015, p. 17. [we frame]

[166] According to the expert, it follows that the expected return of comparable companies, determined by models such as the AFM based on market values, would apply to companies with a financial risk that is significantly lower than that of the Claimants. In the absence of an adjustment for differences in financial leverage, the application of the results of the models would not meet the criterion of reasonable return:

> “[…] *therefore, absent an adjustment to account for differences in financial leverage, the raw model results are not comparable for purposes of determining a fair return, even to the extent the underlying business risk is comparable* ”113.

[167] In response to a RFI from the Régie, Dr. Villadsen explains that the adjustment methods she presents use market values rather than books. It also confirms that with these methodologies, it compares capital structures based on market values of samples of comparable companies with the Plaintiffs' assumed capital structures based on book values.
However, it specifies that its recommendations are essentially based on Hamada's adjustments:

> “ *The Hamada and ATWACC methodologies adjust for differences in financial leverage between the proxy companies' market value capital structure and the Plaintiffs' assumed book (authorized) capital structure. Dr. Villadsen connects*

113 Room B-0015, p. 18.

> *primarily on the ROE estimates derived from the Hamada adjustments because the Regie in the past has been critical of the ATWACC methodology* "114.
>
> [emphasis added]

[168] For his part, Dr. Booth rejects the need for these adjustments and the use of these methodologies, in particular the WACCAI, which are based on market values. He cites Alberta Public Utilities Commission decision U-99099 in support of his position:

> " *In essence, a regulated company's earnings are driven by the portion of the original cost rate base deemed to be financed by common equity. This fact results in a fundamental disconnect from the theory that market capitalization ratios, which have deviated significantly from book capitalization ratios, reflect the appropriate financial risk necessary to determine a fair composite return to be applied to the original cost rate base of a pure play regulated utility. This is because the earnings of a pure play regulated utility are governed by and driven by the regulated return allowed on book equity. In other words, it is the book equity that reflects the appropriate financial risk necessary to determine a fair composite return for a pure play regulated utility* "115. [emphasis added]

[169] Dr. Booth agrees that AIWACC and leverage adjustments are fundamental concepts in modern finance. During the hearing, Dr. Booth explains that the AIWACC is the minimum rate of return that an investment must earn in order to increase the market value of a business. It is a rate of return that maximizes shareholder value116.

[170] Although these are important concepts, he nevertheless considers that their application is inappropriate,117 because it would lead to the abdication of the role of economic regulator. According to the expert, economic regulation is designed to protect tariff payers against the exercise of market power by regulated monopolies and not to maximize value for their shareholders:

> "[…] *The ATWACC is thus a critical concept to understand how a firm can make decisions that enhance shareholder value. In contrast, regulators are not concerned*

114 Room B-0143, p. 96 and 97, R16.8.
115 Part C-ACIG-0087, p. 40. See also decision U99099, November 25, 1999, p. 301.
116 Exhibit A-0063, p. 46.
117 Part C-ACIG-0042, p. 1.

with maximizing or enhancing shareholder value; their mandate is to set "fair and reasonable" rates. This frequently puts them at odds with maximizing shareholder value since regulation should never be designed to enhance or even maintain market values "118.

[171] According to Dr. Booth, the Hamada adjustment suffers from the same problem as the ATWACC, since it readjusts the Betas upwards by applying weights based on the capital structures according to the market values of the samples. companies comparable to the Plaintiffs' assumed capital structures, based on book values119.

[172] In the opinion of the expert, recourse to traditional financial analyses, based on financial statements and book values, should be favored in order to compare financial leverage rather than market values120.

[173] The Régie notes that the proportions of equity observed among the businesses forming the samples of comparable businesses presented by Dr. Villadsen in Table 4 (paragraph 165 of this decision) are calculated from market values121, unlike the alleged proportions of equity of the three Claimants122. Accordingly, the Régie believes that any difference between these proportions of equity established on different bases must be interpreted with caution.

[174] Furthermore, the Régie notes that the financial ratios calculated by the credit rating agencies used to measure the financial health and default risk of regulated companies are essentially established from the financial statements and values at books123.

118 Part C-ACIG-0042, p. 5, lines 9 to 14.
119 Exhibit A-0063, p. 52 and 53.
120 Exhibit C-ACIG-0061, p. 10.
121 Room B-0143, p. 28.
122 Room B-0143, p. 96 and 97.
123 Parts B-0143, p. 18 and 19, and B-0313, p. 10 and 11.

[175] She also notes that financial analysts and financial publications intended for stock market investors use financial statements and securities books to determine various ratios measuring financial risk including, in particular, the financial leverage of companies124.

[176] **The Régie remains of the opinion that, to judge the leverage and the financial risk of companies subject to the regulations and of comparable companies, recourse to a comparative analysis of the financial statements and book values constitutes the traditional approach to be favored for purposes of determining the rate of return on equity.**

[177] The Régie understands that corporate finance is a specialized field of finance that is particularly interested in strategies for maximizing shareholder value. Dr. Villadsen125 and Dr. Booth126 also agree that in corporate finance, it is appropriate to use capital structures based on market values.

[178] However, the Régie shares Dr. Booth's opinion that we must beware of applying this approach to regulated companies127. Unlike the methodologies proposed in corporate finance, the regulator who must set the rate of return of a company does not aim to maximize value for shareholders. Rather, the Régie must, when exercising its functions, ensure a balance between the public interest, consumer protection and equitable treatment of distributors, according to section 5 of the Act. Under section 49 of the Act, it must therefore determine a reasonable return.

[179] Furthermore, the Régie includes the explanations provided in response to the RFIs concerning the Hamada or CMPCAI128 adjustments, whether they are based on the comparison of capital structures, based on the market values of samples of comparable companies , with the Plaintiffs' alleged capital structures, based on book values.

[124] Room B-0313, p. 11 to 19.
[125] Parts B-0143, p. 35, and A-0061, p. 54 and 55.
[126] Part C-ACIG-0042, p. 5.
[127] Part C-ACIG-0042, p. 1, p. 5, p. 9 and 10.
[128] Paragraph 167 of this decision and Exhibit B-0143, p. 96 and 97.

[180] The Régie also notes Dr. Villadsen's explanation justifying this approach:

> " *Dr. Villadsen is not comparing market and book value capital structures. The CAPM and DCF models rely on market data to estimate the cost of equity – implicit in which is the market value of debt and equity. Consequently, to compare the return investors expect on market value equity and that allowed on the equity portion of the rate base, it is necessary to translate the market-value based equity return to one that applies to the equity portion of the rate base. At no point in time does Dr. Villadsen suggests that a rate regulated company should be regulated on the market value of its equity* "129. [emphasis added]

[181] For his part, Dr. Booth refutes the use of market values, either directly with the WACCIP or indirectly through an adjustment for financial leverage calculated from market values:

> " *The above discussion is a critique of the use of the ATWACC for a regulated utility. However, the ATWACC has also been used in a more roundabout way to achieve the same result without applying the ATWACC directly to the book value rate base. This is by using it to generate a financial leverage risk premium that does not in reality exist* "130.

[182] In the opinion of the Régie, a regulated company must be compared, not on the basis of the market value of its equity, but rather on the basis of the value at pounds, as Dr. Villadsen points out. To this end, it may be useful to compare the proportion of equity in the capital structure of these companies with that of the companies in the samples of comparables on a common basis, either according to the value at the books. This makes it possible to see whether the financial leverage is significantly different when using the same basis of comparison.

[129] Room B-0143, p. 29.
[130] Part C-ACIG-0042, p. 10, lines 22 to 25.
[131] Room B-0143, p. 29.

[183] However, the Régie notes in Table 5 that, when Énergir's capital structure is compared with that of the average of the sample of Canadian comparables132 and the average of the sample of American gas distributors133 using the values to books, there is no significant difference in terms of financial leverage.

TABLE 5

Structures de capital (*valeurs aux livres*)	Actions ordinaires	Actions privilégiées	Capitaux propres	Dette
Échantillon entreprises comparables canadiennes	38,4%	4,6%	43,0%	57,0%
Échantillon distributeurs gaziers américains	42,2%	1,7%	43,9%	56,1%
Énergir structure de capital présumée	38,5%	7,5%	46,0%	54,0%

Sources: exhibits B-0143, p. 30, B-0313, p. 4, and B-0015, p. 77.

[184] **The Régie considers that, in the absence of significant differences between Énergir's presumed capital structure compared to the average of the samples of comparable Canadian companies and American gas distributors, measured according to book values, there is no need to make an adjustment for the financial leverage of the TRCP applicable to Énergir compared to the returns of samples of comparable companies.**

[185] The Régie therefore does not retain the approach proposed by the Plaintiffs' expert, based on market values, as the reference approach for determining the reasonable return on the rate base of subject persons. Thus, the Régie does not consider it necessary to examine Hamada's adjustments because Dr. Villadsen applies them to the market capital structure of her Canadian and American samples.

132 Room B-0143, p. 30.
133 Room B-0313, p. 4.

6.2.2 ESTABLISHMENT OF DEEMED CAPITAL STRUCTURES

[186] First, the Régie recalls the principles it used to establish the capital structure in its decision D-96-31:

> " *Consequently, even if the equity ratio of SCGM's capital structure is slightly higher than the average for Canadian distributors, the Régie maintains and hopes that, unless exceptional circumstances justify it, we will not call causes each year this structure that the Régie deems optimal, and which respects the principles that guided it in its decision, namely: ensuring the long-term cost of capital as low as possible, and maintaining the financial health of the distributor.*
>
> [...]
>
> *the objective sought by the Régie in establishing this ceiling was to limit the ratio of common equity of the members because it requires a higher return than the debt, while allowing the distributor to enjoy from year to year 'a capital structure that meets investors* ' expectations'134.

[187] The Régie retains from the Plaintiffs' evidence that the increase in the share of equity in their capital structure is mainly based on their expert's analysis of financial ratios135.

[188] Dr. Villadsen highlights in particular the recent downgrading of the *FFO to* debt136, which is approaching the threshold that could result in a discount for Énergir. However, in her analysis, the expert does not take into account the mentions of S&P indicating that a discount in the next 12 to 24 months would be unlikely, unless this ratio falls below this threshold without possibility of improvement. S&P also mentions that a haircut could occur in the event of an adverse regulatory decision, an acquisition by the non-regulated activity having a significant impact on the debt or operational problems137.

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[134] File R-3351-96 Phase 2, decision D-96-31, p. 65 and 66 (decision of the Régie du gaz naturel available on request).

[135] Room B-0015, p. 77 to 85, A72 to A82.

[136] *Funds from operations (FFO) to Debt :* Ratio of funds from operations to debt.

[137] Room B-0074, p. 3.

[189] In addition, the Régie accepts from the evidence that Dr. Villadsen's analyzes do not take into account the fact that rating agencies can compensate for the weak achievement of one criterion by exceeding another, such as the regulatory environment138 :

> " *In Quebec, where distribution activities account for about half of the energy distribution net income, Energir can recover revenue shortfalls in subsequent years, which reduces its sales volume risk exposure. Furthermore, key rate-base parameters such as return on equity and equity thickness are credit-supportive and in line with those of other jurisdictions* "139.

[190] Dr. Villadsen clarified that she uses generic data to assess financial ratios because she uses them from a forward-looking perspective.

[191] However, in doing so, the expert excludes headings with annual variations such as the amortization of deferred costs and intangible assets, as well as the short-term debt. The evidence shows that the rating agencies take these items into account when establishing Énergir's credit rating.

[192] The Régie notes that the expert's recommendations resulting from her financial ratios serve to provide the Plaintiffs with a financial cushion in the event of an event opponent140. However, it notes that Énergir has an "A" quality credit rating despite its high level of indebtedness, i.e. 67.2% in 2020141 and 65.2% in 2021142.

[193] In this regard, the Régie does not share Dr. Villadsen's statement that her recommendations regarding capital structures are prudent:

> "[…] *Put differently, the ratios that I calculate based on the parameters above are likely to overstate the resulting credit ratio and hence my capital structure recommendations are conservative* "143.

138 Room B-0143, p. 61 and 62, R10.2.
139 Room B-0074, p. 4.
140 Room B-0313, p. 25, R-6.1 and p. 27, R-6.5.
141 Room B-0075, p. 2.
142 File R-4177-2021 Phase 2, exhibit B-0093, p. 2.
143 Room B-0015, p. 118.

[194] The Régie notes that the expert confirms that her calculation of the *FFO to Debt* is done with the net profit after taxes, instead of the net profit before taxes. As this calculation does not take into account the fact that Énergir does not present income tax expenses, but that these expenses are found in the tariffs, the two ratios *FFO Interest Coverage* and *FFO to Debt* are underestimated144.

[195] Dr. Villadsen adds that by calculating the *FFO to Debt,* S&P would have deducted the *cash taxes paid* from the net profit and that its approach is therefore consistent with that of this rating agency145. However, as recalled in response to an RFI of the Régie, this answer contradicts that of Énergir provided in the context of file R-3879-2014146.

[196] Dr. Villadsen submits that, excluding Enbridge Gas Distribution, the share of equity in the capital structures of Énergir and Gazifère is lower than that of Canadian gas distributors. Similarly, still excluding Enbridge Gas Distribution, the Claimants' TRCPs are lower than those of Canadian gas distributors. The expert concludes that this situation is inconsistent with the *fair return standard147 .* The detail of the calculations can be found in confidential exhibit B-0024148.

[197] Questioned by the Régie, the expert confirms that the validity of the comparison and of the conclusion she draws from her findings requires that the distributors of the sample of confidential exhibit B-0024 have risks comparable to those of the Claimants. However, it admits that it did not carry out the required checks in this regard149.

[198] The Régie notes that on the basis of three important indicators, namely the number of customers, the volume of deliveries and annual revenues, the three largest Canadian gas distributors are Enbridge Gas, ATCO Gas and FortisBC Energy. Energize is the fourth largest distributor. Moreover, the sum of all the customers of the

144 Room B-0313, p. 29 and 30, R7.1 to R7.4.
145 Room B-0313, p. 35, R8.3.
146 Room B-0313, p. 34, R8.1 and file R-3879-2014, exhibit B-0539, p. 17 and 18.
147 Room B-0015, p. 16, lines 13 to 20.
148 In response to a RFI from the Régie, confidential exhibit B-0318, p. 3, R-1.1, Dr. Villadsen clarified that the averages presented in confidential exhibit B-0024 (and reported in exhibit B-0015) exclude Enbridge Gas Distribution, because this company has been integrating Union Gas' activities since 2019.
149 Confidential Exhibit B-0318, p. 3, R1.2 and R1.3.

smaller gas distributors than Énergir does not exceed the number of the latter's customers150.

[199] Thus, the Régie finds that Dr. Villadsen's conclusions are based on small Canadian distributors whose risks are not comparable to those of Énergir. In addition, in calculating the TRCP and equity percentages, a very small distributor is separated into three small entities. As a result, TRCP and equity share calculations are biased upwards151.

[200] Thus, the Régie tends to agree with Dr. Booth that the share of equity in Énergir's presumed capital structure should be compared to the average of the three largest gas distributors alone. Canadians, i.e. 37.2 %152.

[201] Moreover, contrary to the opinion of Dr. Villadsen153, the Régie is of the opinion that using the capital structures of US gas distributors requires caution. In this regard, she accepts Dr. Booth's testimony that *the Alberta Utilities Commission* recently ruled on this issue based on evidence filed by Concentric that US regulators do not determine capital structures in the same approach than Canadian regulators154.

[202] With respect to preferred shares, the Régie accepts the comments of Mr. Tremblay, during the hearing, who stated that the capital structure established more than thirty years ago for Énergir corresponds approximately to the real financing structure of the company. However, about 30 years ago, preferred shares were eliminated, so that the real financing structure no longer contains them155.

[203] However, according to this witness, there is no contraindication for Énergir's real capital structure to eventually contain preferred shares. There is also no contraindication to maintaining the deemed preferred shares in the current deemed capital structure. Moreover, he adds that the objective of a

150 Part C-ACIG-0087, p. 5.
151 Confidential Exhibit C-ACIG-0063, p. 3, R1.1.
152 Part C-ACIG-0087, p. 7.
153 Room B-0015, p. 16 and 17, A18.
154 Part C-ACIG-0087, p. 7 and confidential exhibit C-ACIG-0063, p. 7, R1.1.
155 Exhibit A-0054, p. 145 to 147.

regulator is to set a capital structure that allows the regulated entity to minimize its financing costs while having an “A ” credit rating156.

[204] The Régie also holds that Dr. Villadsen's proposal to replace the preferred shares in Énergir's presumed capital structure results in an increase in the level of equity and debt in the latter.

[205] However, as mentioned above, the resulting level of equity of 43% is well above the average equity share of the three largest Canadian gas distributors, namely 37.2%. Thus, the Régie is of the opinion that the replacement of the preferred shares in Énergir's presumed capital structure, all other things being equal, would have the effect of increasing its level of debt.

[206] Such an increase in the level of debt in a capital structure has a direct impact on the profits attributable to shareholders due to the increase in interest charges157. In addition, the increase in the level of debt is often perceived negatively by rating agencies and may therefore lead to higher financing costs158.

[207] The Régie also notes that the average capital structure according to the value at Dr. Villadsen's Canadian sample books contain 4.6% preferred stock159.
The Régie believes that this type of financing is an effective means of minimizing the cost of capital.

[208] Moreover, the Régie notes that Énergir's preferred shares are financing remunerated in the “equity” portion. Thus, replacing them with equity, while preserving the current return provided by the current TRCP of 8.9% and a rate of preferred shares of 5.4%, would be equivalent to remunerating the 46% "equity" at 8 .3 %160.

[156] Exhibit A-0054, p. 159.
[157] Room B-0313, p. 19, R4.5.1.
[158] Room B-0015 p. 112.
[159] Room B-0143, p. 30.
[160] Exhibit A-0054, p. 162 and 163.

[209] With respect to the introduction of preferred shares into Intragaz's capital structure, in order to standardize it with that of Énergir, the Régie refrained from doing so for the reasons given by Mr. Rock Marois, Chairman of Intragaz, in audience161.

[210] However, since the parties are unanimous in acknowledging that the risks of these two companies are similar, the Régie standardizes their return by means of an adjustment of the TRCP of Intragaz to take into account the fact that the capital structure of the latter does not include preferred shares.

[211] Moreover, in its decision D-2011-182, the Régie ruled that Énergir's increased risk compared to a benchmark distributor was offset by its presumed capital structure as well as by maintaining an adjustment to the increase compared to the risk premium of a benchmark distributor163.

[212] In section 5.3 of this decision, based on the risk factors
business, the Régie concludes that the Claimants face a higher level of uncertainty than the level estimated since the last review164.

[213] **In view of the foregoing, the Régie is of the opinion that the current structures remain adequate and that it is appropriate to maintain the Plaintiffs' presumed current capital structures.**

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161 Exhibit A-0054, p. 136 and 137.
162 Refer to section 6.4.5 of this decision.
163 File R-3752-2011 Phase 2, decision D-2011-182, p. 57-59, paras. 226 to 237.
164 Refer to section 5.3 of this decision.

6.3 OPINION OF THE RÉGIE ON THE RATE OF RETURN OF APPLICANTS

6.3.1 EMPIRICAL MODEL FOR THE VALUATION OF FINANCIAL ASSETS (MEÉAF)

[214] The MÉAF is represented by the following equation:

Cost of Capital = *Alpha* + *Risk Free Rate* + *Beta* x *(Market Risk Premium - Alpha).*

[215] The MEAF aims to correct the downward bias stemming from the MEAF for companies with a beta below unity. In the specialized literature, this bias is observed in research carried out using risk-free rates based on the 90-day rates of treasury bills (T-Bills). The correction obtained by introducing an Alpha165 factor into the MEÉAF equation results in an increase in the ordinate at the origin and a reduction in the slope of the linear relationship.

[216] According to Dr. Villadsen, the MEÉAF model is an appropriate model to determine a reasonable rate of return. The expert, in support of the use of the model, cites empirical studies carried out with US treasury bill rates rather than long-term 30-year US government bond rates. It indicates that the Alpha factor, estimated according to empirical studies dating from the 1990s, is between 1% and 7.32%. She considers herself to be conservative by using an Alpha factor of 1.5%.

[217] According to Dr. Booth, the model uses 90-day treasury bill rates to establish a security's return over a 30-day horizon. He considers that the correction for this bias is no longer justified when the estimation model uses long-term government bond yields. According to the expert, the application, based on empirical studies carried out with short-term rates, produces results described as absurd166.

[218] Dr. Villadsen disagrees with this position and argues that the use of long-term bond yields only partially corrects the bias in question. In

[165] See file R-3690-2009, decision D-2009-156, p. 59, para. 235.
[166] Exhibit C-ACIG-0037, p. 56.

response to an RFI167, Dr. Villadsen argues that short-term rates are not appropriate to determine the reasonable return of a regulated company. She adds that short-term rates are volatile and are not matched to the economic life of the assets being financed.

[219] **In the context of previous files on the determination of the rate of return, the Régie has already ruled that the correction of the results of the MEAF model made by the MEAF was not sufficiently justified. The Régie considers that there are no new elements prompting it to reconsider this approach.**

6.3.2 DISCOUNTED CASH FLOW MODEL (AFM)

[220] There are several versions of the AFM discounted cash flow model. Dr. Villadsen produced results using the best-known version of this model, namely the simple version in which dividend growth is assumed to be constant over time. It also produced results using a version in which the growth of dividends converges, over a 10-year horizon, to the expected growth of GDP168.

[221] Since the growth rates of the first version are higher than those of the second, the resulting rates of return are also higher. For example, Dr. Villadsen uses both versions of the AFM to determine ranges of rates of return for the samples of Canadian and American companies.

[222] Dr. Villadsen adjusts the results of the AFM models using the AIWACC method to take into account the fact that she uses market-valued capital structures169.

[223] Furthermore, the expert submits that there is academic research that shows regulatory reforms have eliminated the optimism bias associated with financial analysts' forecasts. This situation would therefore be a problem of the past. Other academic research would show that the optimism bias persists for stocks that are difficult to evaluate, especially those for which there are disagreements between analysts.

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167 Room B-0143, p. 88.

168 Room B-0015, p. 70 to 75, A65 to A70 and p. 107 to 111.

169 Refer to section 6.3.1 of this decision.

[224] However, as shown in the following table, the Régie notes the low number of analysts per company in the American samples.

TABLE 6

GROWTH RATES IN DR . VILLADSEN 'S AFMs

Sample	Combined rate IBES / Value Line	Number of BIES analysts	Value Line
Canadian Holdings	5.3%	Between 2 and 4 analysts per company	A forecast for Enbridge and Fortis. None for others
Distributors united states gas companies	6.3%	1 analyst per company except 3 for Atmos Energy	One forecast per company
Water services	7.8%	1 analyst per company	One forecast per company. None for Artesian Res Corp and Global Water Res.

Sources: Table prepared by the Régie using exhibit B-0015, table BV-4.5 and exhibit B-0015, table BV-5.5.

[225] The Régie notes that the growth forecasts of *the Institutional Broker's Estimate System* (IBES) and of Value Line are based on forecasts of earnings per share over a horizon of three to five years, without however guaranteeing that each forecast covers exactly the same horizon. She also notes that a BIES forecast can be in effect for up to 180 days.

[226] In addition, among the 20 BIES forecasts related to Canadian holding companies, 11 come from unidentified analysts171. Among the 19 forecasts linked to American companies, 12 come from unidentified analysts172.

[227] For these reasons, the Régie is of the opinion that the companies in Dr. Villadsen's samples do not benefit from broad analyst coverage and transparency of information. Thus, in this situation, she considers that it would be imprudent to affirm the absence of analysts' optimism bias173.

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170 Room B-0143, p. 14, R4.4.
171 Room B-0143, p. 12, table of response R4.1.
172 Room B-0143, p. 13, table in response R4.3.
173 Room B-0015, p. 110 and 111.

[228] Moreover, the Régie accepts Dr. Booth's explanations indicating that simple MFA amounts to postulating that the rate of return expected by an investor is the sum of the expected return on dividends and their expected growth. This model is valid provided that the long-term growth of dividends is constant. In practice, this means that simple MFA applies to very low-risk companies or to the entire stock market174.

[229] The Régie also accepts Dr. Booth's opinion that earnings growth forecasts contain an optimism bias and that multilevel AFM models do not eliminate this bias but mitigate its impacts.

[230] **Consequently, the Régie does not retain the results of the Plaintiffs' AFM. In continuity with its previous decisions, including decisions D-2011-182 and D-2014-034175, the Régie is of the opinion that the MEAF remains the most appropriate reference model for determining the Claimants' TRCP.**

[231] However, a single model cannot on its own correctly represent investors' expectations in all circumstances and in all phases of the economic and financial cycles, particularly in the present context of high inflation.

[232] In this regard, the Régie notes that due to the recent period of very low Canada bond yields, Dr. Booth questions the use of the AFM for the purpose of validating the results of the MEAF.

[233] She notes in particular that according to the latter, when inflation accelerates, it is captured by the AFM. However, in this situation, bond yields do not rise as fast as inflation, so the results of the AFM are higher than those of the MEAF.

[234] **Thus, the Régie adds to the results of the MEAF a range of 50 to 100 basis points to take into account Dr. Booth's explanations regarding the discrepancies between the historical results of the MEAF and the AFM176.**

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[174] Exhibit C-ACIG-0037, p. 68 to 71.

[175] Files R-3752-2011 Phase 2, decision D-2011-182, p. 59 and 60, paras. 242 and 243, and R-3842-2013, decision D-2014-034, p. 51-54, paras. 195 to 207.

[176] Exhibit C-ACIG-0037, p. 71 to 75.

6.3.3 FINANCIAL ASSETS MEASUREMENT MODEL (FAEM)

[235] According to the MEAF, the cost of capital of a financial asset is explained by the risk-free rate and its systematic risk (Beta factor) multiplied by the market risk premium.

Cost of Capital = *Risk Free Rate* + *Beta* x *Market Risk Premium*

Risk-free rate

[236] Dr. Villadsen proposes the use of two scenarios with respect to the risk-free rate and the market risk premium. The same Betas are used in both scenarios.

[237] Both scenarios are based on the forecast yield on 30-year Canadian bonds at a rate of 2.30%. The expert derives this value using the *Consensus Forecast* of June 2021, that the yield on 10-year Canada bonds would reach 1.9% in June 2022. To this forecast, she adds a historical yield spread (1990–2021) of 40 basis points between 10-year bonds and 30 years old.

[238] In a context of low interest rates, the expert estimates that credit spreads177 contemporaries are higher than those that prevailed before the financial crisis of 2007-2008178. In the first scenario, this difference between the credit spreads is taken into account in the risk-free rate that the expert establishes at 2.47%. This is the forecast of Canada's 30-year bond yield plus half the credit spread as of June 2021179.

[239] Moreover, in order not to double count the effect of credit spreads, the expert uses in this scenario a market risk premium calculated using historical data180.

[240] In the second scenario, the risk-free rate corresponds to the projected return for 2022 on 30-year Government of Canada bonds, namely 2.30%. The

177 Spread between 30-year A-rated utility bond yields and those of Canada.

178 Room B-0015, p. 34 to 36, A33 and

179 A34. 2.47% = 2.30% + ½ x (1.33% – 0.99%). Refer to Exhibit B-0015, p. 100, Table A-1, for details of the 1.33% and 0.99% credit spreads.

180 Room B-0015, p. 64, lines 6 to 14.

difference in credit spreads is factored into a market risk premium calculated using Bloomberg.

[241] Details relating to the market risk premium are presented in the next subsection.

[242] The risk-free rates for the two scenarios, according to the May 2022 update, are 3.77% and 3.40 % respectively181. The risk-free rate of the first scenario incorporates, as in the initial proof of June 2021, the difference between credit spreads.

[243] Moreover, questioned by the Régie during the hearing, Dr. Villadsen estimated that long-term rates should be in a range of 3.4% to 4.0% for the next two years182.

[244] The risk-free rate advocated by Dr. Booth is 3.8%.

[245] In response to a RFI from the Régie183, the expert Booth recalls that in the absence of the " *Twist* "184 operation of the *Federal Reserve System* (the Fed) in 2011 and 2012, he estimated that the return long-term Government of Canada bonds was 3.8%. This estimate used the difference between the yields of "A" rated corporate bonds and those of preferred shares185.

[246] The expert adds that the data to measure this gap are no longer available, but he is of the opinion that this rate of 3.8% is still adequate. In addition to central bank action, the expert says demographic shifts and slowing economic growth explain the downward trend in Canada's long-term bond yields since the early 2010s.

[181] Exhibit B-0364.

[182] Exhibit A-0061, p. 45.

[183] Exhibit C-ACIG-0061, p. 2 and 3, R1.1.

[184] A " *Twist* " operation is a central bank's monetary policy whereby the bank simultaneously buys long-term bonds and simultaneously sells short-term bonds with the aim of stimulating the economy by reducing long-term interest rates term and increase those in the short term.

[185] File R-3842-2013, exhibit C-AQCIE-CIFQ-0023, p. 42 and 43.

[247] Questioned by the Régie during the hearing, Dr. Booth submits that a reasonable range of Canada long-term bond yields for the next few years is between 3.0% and 3.5 %186.

[248] The Régie notes that the experts have different opinions on the extension and impacts of geopolitical uncertainties, inflation, and central bank actions in the coming years, which explains the different ranges they propose.

[249] On the one hand, in support of his recommendation of lower risk-free rates than those of Dr. Villadsen, Dr. Booth submits that the growth of the economy will be higher than that of inflation. He is of the opinion that the Bank of Canada will not have the necessary will to increase its key rate in order to counter inflation187. The expert also submits that there is no stagflation in Canada and that, in his opinion, there will not be188.

[250] On the other hand, during the hearing, Dr. Villadsen observes that the Fed recently raised the federal funds rate by 75 basis points and that this is a significant increase. It also notes the Bank of Canada's desire to raise its key rate to counter inflation189.

[251] In its assessment of the range of the risk-free rate, the Régie cannot assume a specific scenario of economic growth or the evolution of inflation and interest rates. Nor can it assume that changing economic and financial conditions will subside in 2023 as submitted by ACIG190.

[252] In addition, the Régie agrees with Dr. Villadsen's opinion that estimating an upper bound for Canada's long-term rates is a matter of conjecture191.

[253] **Thus, given the foregoing, the Régie retains a risk-free rate range of 3.25% to 4.25%.**

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186 Exhibit A-0063, p. 208 and 209.
187 Exhibit A-0063, p. 217 to 219.
188 Exhibit A-0063, p. 221 to 224.
189 Exhibit A-0061, p. 45.
190 Part C-ACIG-0102, p. 3, para. 6.
191 Exhibit A-0061, p. 45.

Market risk premium

[254] Dr. Villadsen explains that the market risk premium (MRP) is a forecasting concept. It corresponds to the expectation of the additional return of investments in the market, compared to the return of a risk-free investment.
PRM cannot be observed directly. Its value is obtained from an estimate or forecast based on market data.

[255] As mentioned above, the expert's first scenario incorporates the difference in credit spreads into the risk-free rate. Thus, it uses an MRP corresponding to the arithmetic average of historical annual MRPs in Canada between the years 1935 and 2020. This historical average MRP is 5.68%. The annual PRMs come from the firm Duff & Phelps192.

[256] Estimation of historical data is a commonly used method for estimating MRP. The MRPs for the 1919-2020 and 1945-2020 horizons are established
5.54% and 5.80 % respectively193.

[257] The MRP for the second scenario is set at 8.05%. This is a forward-looking MRP determined using Bloomberg. It is calculated relative to 10-year Canada bond yields and then adjusted relative to 30- year Canada bond yields194.

[258] According to Dr. Villadsen, there is an inverse relationship between the MRP and the risk-free interest rate. This relationship would be demonstrated by academic analyses195. Furthermore, Bloomberg's forward-looking MRP is higher than the historical MRP. In addition, the forward-looking MRP against 10-year Canada bond yields increased from 7.25% at the end of 2019 to 8.45% at the end of June 2021. For these reasons, the expert is d I believe the historical MRP is lower than investors' expectations.

[259] According to a *Staff Report* from the *Federal Reserve Bank of New York* published in 2015, the MRP would have reached an unprecedented level in 2012 and 2013. According to the expert, this trend is confirmed by Bloomberg data and is similar to the one who observes

192 Room B-0015, p. 42, footnote 91 and confidential exhibit B-0040.
193 Room B-0015, p. 100.
194 Room B-0015, p. 62, A57 and footnote 137 as well as confidential exhibit B-0019 (Excel file).
195 Parts B-0015, p. 42, lines 4 to 9, B-0038 and B-0039.

following the pandemic-induced financial crisis. For this reason, it submits that the MRP will remain high, compared to its historical level.

[260] According to the May 2022 update filed by the Claimants, Canada's historic MRP goes from 5.68% to 5.91 %196. Bloomberg's prospective MRP for Canada decreases from 8.05% to 5.86 %197.

[261] Dr. Booth assesses the historical MRPs of Canada and the United States over the 1926-2021 horizon at 4.80% and 6.36% respectively.

[262] However, he recommends an MRP for Canada in the range of 5.5% to 6.0%. This range incorporates the recommendations of Duff and Phelps, Prof. Aswath Damodaran, the survey by Prof. Pablo Fernandez and the Credit Suisse " *Global Investment Returns Yearbook* " report. This range also incorporates forecasts for the United States, since there are, in particular, significant movements of Canadian capital abroad and of foreign capital in the Canadian bond market.

[263] Moreover, with the help of Professor Fernandez's investigations, Dr. Booth submits that there is no proof indicating that since 2011 the PRM and the interest rates vary in opposite directions. He adds that he does not know of contemporary studies on this subject, especially since the decrease in inflation in Canada and the United States.

[264] The explanations provided by Dr. Villadsen regarding the forward-looking MRP calculated by Bloomberg show, in particular, that the long-term growth rate of dividends implicit in this MRP is higher than that of Canadian GDP (3.7 %)198.

[265] The Régie is of the opinion that the prospective MRP used by the Plaintiffs' expert is questionable, since analysts' estimates often turn out to be overly optimistic and the short-term growth rate is high over an infinite horizon. In addition, it considers the credit spread adjustment to be one-time in nature. These are the same shortcomings as

[196] Exhibit B-0364.
[197] Room B-0350, p. 36.
[198] Confidential Exhibit B-0318, p. 8, R2.8.

the prospective PRM used by Concentric rejected in file R-3842-2013 and it must reject the approach proposed by Dr. Villadsen for the same reasons199.

[266] In its decision D-2011-182, the Régie reiterated its preference for a historical MRP, used since 1996. It pointed out, however, that the choice of reference periods to establish the MRP raises certain issues. Indeed, the calculated average may differ significantly depending on the start and end year and the series of data used. In this context, the Régie chose to give preponderance to averages over long periods200.

[267] **Considering the foregoing, the Régie does not accept the reasons invoked by the Plaintiffs for the use of a prospective PRM. It maintains that the establishment of the MRP must be based on historical data of long periods.**

[268] The Régie notes that the historical MRPs for Canada provided by the Plaintiffs' expert and according to the horizons considered are between 5.54% and 5.91%.

[269] She also notes that the historical MRP of Canada, reported by Dr. Booth, is lower than those reported by Dr. Villadsen. The horizons of the PRMs used by the two experts are not the same but do not explain the difference observed for the following reasons.

[270] Based on the information provided by Dr. Villadsen on Canada's MRP over the 1935-2020 and 1935-2021 horizons, the Régie concludes that Canada's MRP in 2021 is around 25.69%. Indeed, although the 2021 PRM is not available in confidential exhibit B-0040, it can be deduced from the two historical PRMs provided by the expert201.

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199 File R-3842-2013, decision D-2014-034, p. 43-45, paras. 157 to 169.

200 File R-3752-2011 Phase 2, decision D-2011-182, p. 55, para. 215 and

201 216. 5.91% = 5.68% x (86 ÷ 87) + 25.69% ÷ 87, where 86 and 87 correspond to the number of years between 1935 and 2020 and 1935 and 2021 respectively. 25.69% can also be verified using the data in confidential exhibit B-0040.

[271] This 2021 MRP, estimated using data from confidential exhibit B-0040, also makes it possible to estimate Canada's MRP over the 1926-2021 horizon according to the data used by Dr. Villadsen and the compare to Dr. Booth's MRP. The spread between the two MRPs is approximately 100 basis points.

Historical PRM on the horizon 1926-2021

According to Dr. Booth:	4.80%
Using data from Dr. Villadsen as estimated by the Régie:	5.81%

[272] Dr. Booth calculates stock market returns and Government of Canada bond market returns taking into account capital gains. He also submits that the methodology used by Dr. Villadsen, namely that of Duff & Phelps, excludes capital gains in the calculation of returns on the Government of Canada bond market202.

[273] Moreover, the Régie notes that the American data tab of exhibit B-0040 cited by Dr. Villadsen in a response to a RFI from Dr. Booth on the methodology of Duff & Phelps203, contains the mention “ * *S&P 500 total returns minus long-term government bond income returns*”204. In other words, Duff & Phelps' US MRP does not take into account capital gains from the Government of Canada bond market. However, this exhibit does not specify the methodology used for Canada's SMRs.

[274] In addition, the Régie notes that Dr. Booth's MRPs are based on arithmetic averages205.

[275] Thus, for the reasons set out above, the Régie is of the opinion that the main difference between Dr. Booth's SMRs and those of Dr. Villadsen lies in the treatment of the yield of the Government of Canada bond market.

202 Exhibit C-ACIG-0037, p. 2, lines 20 to 22.
203 Room B-0193, p. 19, R7.3.
204 Confidential Exhibit B-0040, “United States LCL LT” tab, cell A107.
205 Exhibit C-ACIG-0039, p. 24, appendix 9.

[276] The Régie also points out that it arrived at a result similar to that produced above in its decision D-2014-034, namely a difference of approximately 100 basis points between an MRP calculated excluding capital gains in the calculation of Government of Canada bond market returns and another spread obtained from the difference between the total return of the stock market and the total return of bonds206.

[277] In the absence of a substantive debate on the advantages and disadvantages of these two possible approaches to calculating the return on the Government of Canada bond market in a historical SMR context, the Régie does not rule on the best methodology to use in this case.

[278] However, in its determination of a range of market risk premiums, it takes into account all the historical Canadian and American SMRs presented by the parties' experts. It also takes into account the representations of the Claimants indicating that it is relevant to weight the historical averages according to the current economic context, since the capital markets undergo certain variations, in particular during periods of great uncertainty207.

[279] **Consequently, the Régie adopted a range for the market risk premium for the MEAF of the benchmark distributor of between 5.50% and 6.00%.**

Beta

[280] In applying the concept of isolation, a benchmark company is a utility with a low level of risk. The risk of an anchor distributor is measured by the Beta factor, which represents the difference between the risk of an anchor distributor and the market in general.

[281] Dr. Villadsen determines the Beta factors using Bloomberg based on a calculation of weekly returns over a three-year period. It adjusts these Betas according to Blume's formula208.

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206 File R-3842-2013, D-2014-034, p. 46, para. 172 and 173.

207 Room B-0388, p. 25, para. 114.

208 Room B-0015, p. 103.

[282] In this regard, the expert mentions that Bloomberg, Value Line and other investor services firms make it possible to adjust the unadjusted Betas (or raw Betas) in order to improve their precision. She adds that Adjusted Betas are commonly used in the application of the CAPM and recognized by several regulatory agencies209.

[283] There is a Beta factor for each of the three samples made up of Canadian gas holdings, US gas distributors and US water utilities.
These factors, as of June 2021, are 0.91, 0.95 and 0.84210 respectively. Dr. Villadsen points out that the Betas have gotten stronger over the past two years.

[284] The Betas presented in the May 2022 update filed by the Claimants are similar to those of June 2021211.

[285] Dr. Booth, for his part, uses Betas ranging between 0.50 and 0.55. These come, among other things, from an analysis of raw Betas since 1998 of a Canadian utility index. Returns for this index were calculated monthly over five-year rolling windows and compared to the return of the TSX.

[286] Unlike Dr. Villadsen, Dr. Booth does not use corporate samples for Beta determination purposes. It calculates Betas for individual Canadian and US companies for validation purposes. He also consults the Betas provided by RBC, Yahoo, CFRA and Reuters.

[287] According to Dr. Villadsen, the Beta she proposes is higher than what was known for regulated companies in the past. This increase could be explained by the prolonged impacts of the financial crisis212.

[288] However, the Régie notes that Dr. Villadsen's sample of Canadian gas holding companies includes Enbridge Inc. and TC Energy Corp. According to Dr. Booth, these companies have seen their Beta increase significantly because of the difficulties they are having in advancing their pipeline expansion projects in Canada and the United States.

209 Exhibit B-0079.

210 Room B-0015, p. 53, table 18 and p. 59, tables 20 and 21.

211 Exhibit B-0364.

212 Room B-0388, p. 31, para. 144.

United States213. The Régie considers that this explanation is more convincing than that provided by Dr. Villadsen on the evolution of the Betas of these two companies214.

[289] The Régie also notes that the natural gas distribution sector in Canada and the United States is characterized by numerous mergers and acquisitions215. She notes that it is becoming increasingly difficult to assess a Beta for a benchmark company in a context where the samples are made up of companies whose activities can be diversified both in terms of their activities and the various jurisdictions (states, provinces) in which they do business.

[290] Moreover, the Régie notes that the two experts do not agree on the periodicity to be used in order to sample stock market data for the calculation of Betas.

[291] Dr. Villadsen submits that the use of Betas calculated according to weekly data over a period of three years increases the reliability of the results, because they improve the statistical reliability compared to monthly observations and this use makes it possible to adequately capture the environment. of the current market.

[292] However, the Régie is not convinced by Dr. Villadsen's response to the effect that the volatility of Betas is higher when calculated from monthly data over a five-year horizon rather than weekly data over a three- year horizon217.

[293] She is of the opinion that Dr. Booth's explanations about the bias induced on the Betas by the weekly sampling are more convincing218. The Régie notes that these explanations are based on an article published in a reputable investment management journal.

[294] With respect to the contemporaneity of the data, Dr. Villadsen indicates that using too short a horizon implies that current conditions will extend over time.

213 Part C-ACIG-0040, p. 6, lines 9-12.
214 Confidential Exhibit B-0154, p. 17, R4.1.
215 Parts B-0015, p. 48 and 49, A45, and C-ACIG-0040, p. 6, lines 20 to 27 and p. 7, lines 1 to 4.
216 Exhibit A-0058, p. 116.
217 Confidential Exhibit B-0154, p. 12, R3.1.
218 Part C-ACIG-0040, p. 10 and 11.

[295] However, according to the Régie, the risk of a benchmark distributor in relation to the market cannot fluctuate significantly from one year to the next according to changes in the economic situation. This development is rather taken into account in the specific risk of each company it regulates. Although a benchmark distributor's Beta may fluctuate over time, the risk remains stable.

[296] The Régie also notes that the two experts do not adjust the Betas using the same method.

[297] According to Dr. Villadsen, the objective of adjusting the Betas according to the Blume formula is to correct a sampling error and not to make them converge towards a value of 1. In the context where the result of the MEAF is used for prospective purposes, it believes it is appropriate to use Adjusted Betas.

[298] However, the Régie is of the opinion that Blume's formula, as used by Dr. Villadsen219, is based on the assumption that the Beta of a security tends in the long term towards the market average. In the context of SCGM's 1998-1999 rate case220, the Régie ruled for the first time on the issue of adjusted Betas as opposed to raw Betas:

> " *According to the documents filed, the majority of recognized investment houses, such as Value Line, Bloomberg and others, publish as part of their analyzes of returns on the markets adjusted betas.*
>
> *On the other hand, this trend of betas towards 1.0 is not so evident for regulated sectors such as the distribution of natural gas. IGUA's evidence indeed calls into question the appropriateness of using the general adjusted beta[s] theory unreservedly for regulated firms. In the absence of being able to directly measure the beta of SCGM, the experts must resort to estimates based either on a sample of comparable companies, or on general studies* "221. [emphasis added], [footnotes omitted]

219 Room B-0015, p. 103 and confidential exhibit B-0154, p. 13, R3.3.

220 Société en commandite Gaz Métro, namely the name of Énergir in 1998.

221 File R-3397-98, decision D-99-11, p. 46.

[299] Since this decision, as the following table shows, the Régie has always retained unadjusted Betas for the purposes of the MEAF of a benchmark company222.

TABLE 7

BETAS RETAINED BY THE RÉGIE SINCE ITS DECISION D-99-11

FOR THE PURPOSES OF THE BENCHMARK DISTRIBUTOR MEAF

Case	Regulated company	Decision	Unadjusted beta
R-3842-2013	Hydro-Quebec (HQT/HQD)	D-2014-034, p. 40 to 42	0.48 – 0.58
R-3807-2012	Intragas	D-2013-08, p. 38	0.50 – 0.60
R-3752-2011	SCGM (Énergir)	D-2011-182, p. 56 and 57	0.50 – 0.60
R-3724-2010	Gasiferous	D-2010-147, p. 20	0.50 – 0.55
R-3690-2009	SCGM (Énergir)	D-2009-156, p. 65	0.50 – 0.55
R-3630-2007	SCGM (Énergir)	D-2007-116, p. 27	0.50 – 0.55
R-3492-2002	Hydro-Quebec (HQD)	D-2003-93, p. 72 and 73	0.55
R-3401-98	Hydro-Quebec (HQT)	D-2002-95, p. 165 and 166	0.53
R-3397-98	SCGM (Energir)	D-99-11, p. 46	0.55

[300] The Régie finds that the explanations provided by Dr. Villadsen are no different from those provided by the experts in the previous cases to support the use of the Blume adjustment.

[301] The Régie also notes that it is normal for the difference between an adjusted Beta of between 0.85 and 0.95, as proposed by Dr. Villadsen, and an unadjusted Beta to be small. Indeed, Blume's formula is constructed in such a way that the adjustment is zero if the unadjusted Beta is 1, and 0.67 if it is zero223. According to the level of Betas established by Dr. Villadsen using her samples and three-year weekly data, the difference between unadjusted and adjusted Betas is approximately 0.05224.

222 The Intragaz decision does not specify whether Beta is adjusted or not. However, the Régie did not retain the AFM model recommended by the plaintiff's expert. She opted instead for a DEAF like the one proposed by Dr. Booth.

223 Confidential Exhibit B-0154, p. 13, R3.3.

224 Room B-0350, p. 20.

[302] The Régie is of the opinion that the explanations provided by Dr. Booth regarding the Beta adjustment are convincing225. **Thus, it maintains its conclusion expressed many times to the effect that in the presence of exclusive distribution rights, it is difficult to conceive how the risk specific to a benchmark distributor could change substantially upwards and evolve towards the risk of the market over the years.**

[303] For this reason, the Régie is of the opinion that even if the Beta range presented by Dr. Villadsen was not adjusted according to Blume's formula, it remains at a level too close to 1, namely order of 0.85, to represent the risk of a benchmark distributor.

[304] However, this does not necessarily fully resolve the problem related to the quality of the raw Betas and their ability to correctly predict returns in the context of the application of the MEAF. There is an increasing difficulty in inferring the Beta value of a benchmark distributor objectively from stock market data. **Consequently, based on the evidence in the file, the Régie establishes the Beta of a benchmark distributor within a range of 0.50 to 0.60.**

Issuance costs

[305] To arrive at her recommendations, Dr. Villadsen uses several methodologies and proposes different hypotheses and adjustments, as presented above. However, it does not make use of a provision for issue costs and other capital market access costs.

[306] Dr. Booth also presents different methodologies, assumptions and adjustments. For its part, it uses a provision for issue costs and other capital market access costs of 0.50% to establish its TRCP recommendation of 7.50 %226.

[307] The Régie points out that issue costs and other capital market access costs were authorized in several previous decisions227 relating to

225 Part C-ACIG-0040, p. 7 to 10.
226 Exhibit C-ACIG-0037, p. 3.
227 Files R-3690-2009, decision D-2009-156, p. 68 and 69, R-3724-2010, decision D-2010-147, p. 24, and R-3752-2011 Phase 2, decision D-2011-182, p. 59.

Énergir et Gazifère, such an adjustment being in accordance with the principle of isolation, compatible with the practice applied by several regulators and not disputed in this case.

[308] **Consequently, the Régie established a range for the provision for issue costs and other capital market access costs of 30 to 50 basis points.**

6.3.4 RATE OF RETURN FOR A BENCHMARK DISTRIBUTOR

[309] The table below presents the MEAF for a benchmark distributor according to the ranges of values retained for each of the parameters. In this MEAF, the Régie also takes into account Dr. Booth's explanations regarding the discrepancies between the historical results of the MEAF and the AFM.

TABLE 8

VALUES RETAINED FOR THE PURPOSES OF A BENCHMARK DISTRIBUTOR 'S MEAF

Setting	**Bottom of the fork**	**Top of the fork**
Risk-free rate	3.25%	4.25%
Market risk premium	5.50%	6.00%
Beta for a benchmark distributor	0.50	0.60
Issuance costs	0.30%	0.50%
Subtotal: Result produced by the MEAF	**6.30%**	**8.35%**
Adjustment to account for differences between the historical results of the MEAF and the AFM	0.50%	1.00%
Total: TRCP of a benchmark distributor	**6.80%**	**9.35%**

6.3.5 APPLICANTS ' RATE OF RETURN

[310] In order to establish the Plaintiffs' TRCP, the Régie takes into account their own level of risk compared to a benchmark distributor, through adjustments made to the TRCP on the shareholders' equity of a benchmark distributor228.

[311] As established in section 5.3 of this decision, the Régie estimates that Énergir's risk in relation to a benchmark distributor is between 25 and 45 basis points. It also estimates that Gazifère's risk compared to a benchmark distributor is between 40 and 60 basis points.

[312] The following table presents the TRCP ranges for Énergir and Gazifère resulting from taking into account their specific risks, compared to a benchmark distributor.

TABLE 9

TRCP RANGE FOR ENERGY AND GAS

Setting		**Bottom of the fork**	**Top of the fork**
TRCP of a benchmark distributor (table 8)	(has)	6.80%	9.35%
A. Adjustment for the risk of Énergir	(b)	0.25%	0.45%
TRCP for Énergir = (a) + (b)		**7.05%**	**9.80%**
C. Adjustment for Gazifère's risk	(vs)	0.40%	0.60%
TRCP for Gazifere = (a) + (c)		**7.20%**	**9.95%**

[313] Thus, taking into account all of the preceding conclusions, the TRCP to be authorized for Énergir is within a range of 7.05% to 9.80%. That of Gazifère is between 7.20% and 9.95%.

228 File R-3752-2011 Phase 2, decision D-2011-182, p. 59, par 236 and p. 74, table 4.

[314] **Based on the evidence in the record and for all of the reasons expressed above, the Régie maintains the presumed capital structure of the Plaintiffs, namely:**

- **38.5% equity, 7.5% preferred stock and 54% debt for Energize;**

- **46% equity and 54% debt for Intragaz;**

- **40% equity and 60% debt for Gazifère.**

[315] **It determines the TRCP on Énergir's equity at 8.90%, for application to the 2022-2023 tariff year, starting on** October **1 , 2022.**

[316] **The Régie determined the TRCP on Gazifère's equity at 9.05%, for application to the 2023 tariff year, starting on** January **1 , 2023.**

[317] With respect to Intragaz's TRCP, the Régie notes that, apart from the issue of the maturity premium, the parties agree on the fact that the risks of this company are similar to those of Énergir and that consequently, the capital structure and the TRCP of these two companies should be equivalent229.

[318] With respect to the maturity bonus proposal, the Régie considers that it is not appropriate to follow up on Dr. Villadsen's recommendation to grant such a bonus to Intragaz. This proposal by Dr. Villadsen is based on a decision by *the Iowa Utilities Board.* However, the Régie considers that the legal framework of this body differs from that of Intragaz. Furthermore, Intragaz's main risk with this multi-year contract is that of not being paid by Énergir. However, the evidence is to the effect that this risk is linked to Énergir's risk of being able to receive the necessary revenues for the purpose of paying its suppliers. Dr. Booth even emphasizes that this 10-year contract has the effect of reducing Intragaz's risks and not increasing them230, but he indicates that he has no difficulty in allocating equivalent financial parameters, since he considers that Énergir and Intragaz are, for all intents and purposes, integrated companies.

229 Exhibit A-0054, p. 135.

230 Part C-ACIG-0087, p. 4.

[319] The Régie also accepts that Intragaz confirms that it is in agreement with Dr. Villadsen's proposal to link its rate of return to that of Énergir over the 2023-2032 horizon231. According to the plaintiff, this is a streamlined approach that makes it possible to adjust Intragaz's TRCP based on changes in the financial context, having Énergir's TRCP as a reference.

[320] However, the remuneration of the 46% " *equity* " of Intragaz and Énergir is based on the one hand on 46% equity and on the other hand on 38.5% equity and on 7, 5% preferred stock.

[321] Thus, in order to link Intragaz's TRCP to that of Énergir, while ensuring that their rate of return on " *equity"* is equivalent, the Régie uses the calculation presented by Mr. Énergir's Tremblay in hearing232. As an illustration of the calculation of Intragaz's TRCP using that of Énergir, the Régie uses the rate for Énergir's preferred shares, provided by the latter in its 2021-2022 tariff file, namely 5.412 %233 :

$$8.33\% = (8.90\% \text{ x } 38.5\% + 5.412\% \text{ x } 7.5\%) \div 46\%.$$

[322] In other words, a TRCP of 8.9% based on a capital structure composed of 38.5% equity and 7.5% preferred shares remunerated at a rate of 5.412%, provides a return equivalent to a TRCP of 8.33% on 46% equity.

[323] **For the reasons expressed above, the Régie determines that the TRCP of Intragaz will be linked to that of Énergir over the period from** May **1 , 2023 to April 30, 2033 so that their rate of return on "** ***equity*** **" is equivalent depending on their own capital structure.**

231 Room B-0325, p. 1, R1.1.
232 Exhibit A-0054, p. 163.
233 File R-4151-2021, exhibit B-0054, row 6, column 7.

[324] **Given that the update of the average effective rate of preferred shares was not filed in rate case 2022-2023234, the Régie is asking Énergir to file this update, within a maximum of two weeks. from this decision, according to the same methodology235, in order to approve Intragaz's final TRCP in a future decision.**

[325] Furthermore, in response to an RFI from the Régie, Intragaz proposes a simplified method that would link its TRCP to that of Énergir over the period from May 1 , 2023 to April 30, 2033236.

[326] The Régie is of the opinion that the proposed method complies with the conclusions of this decision, namely that Intragaz's business risks are similar to those of Énergir. This method also represents a reasonable compromise between the accuracy of an approach based on expert evidence and the benefits of regulatory relief for a company the size of Intragaz.

[327] **Consequently, the Régie approves the streamlined method, proposed by Intragaz in exhibit B-0325, which makes it possible to link its TRCP to that of Énergir over the period from** May **1 , 2023 to April 30, 2033. In the application of this method, the Régie orders that the rule linking the TRCP of Intragaz to that of Énergir is based on the principle used in this decision, namely that the rate of return on *the "equity* " of the two companies be equivalent according to of their own capital stru**

[234] File R-4177-2021.

[235] File R-4151-2021, exhibit B-0054.

[236] Room B-0325, p. 1 and 2, R1.2.1.

7. PERIOD OF APPLICATION

[328] In this case, the Régie asked participants for their position on a period of application of rates of return and capital structures. The objectives targeted by the Régie are efficiency, stability and regulatory relief, as well as the reduction of regulatory costs. The Régie is of the opinion that a multi-year application period could make it possible to avoid repetitive requests relating to the rate of return, as observed in decision D-2011-182237.

[329] In response to an RFI from the Régie238, the Plaintiffs indicate that they are generally in favor of regulatory relief, particularly with regard to the determination of the rate of return, but believe that a period of five years is a bit long to the light of the experience of the last 20 years, when the periods went up to three years.

[330] In addition, they submit that the framework allowing the review of the rate of return during the period that the Régie could determine should be specified, as it noted in its decision D-99-011:

> " *The Régie also notes that, during the testimony, certain reservations about the use of an automatic formula to periodically adjust the rate of return were expressed and that various parameters, to limit or justify possible interventions before the Régie, were been suggested. The Régie is of the opinion that such an adjustment mechanism will only be effective and valid if, while ensuring the maintenance of a healthy financial situation for the distributor, the rules and circumstances of the review are clear to all parties. interested* "239.

[331] In its argument, ACIG suggests reviewing the rate of return and the capital structure, within the framework of a new hearing in three years240.

[332] The Régie notes the relevance of the request to specify the framework of a period of application. The Régie recognizes that the Plaintiffs are entitled to a reasonable rate of return ensuring them a healthy financial situation. However, it must assess

[237] File R 3752-2011 Phase 2, decision D-2011-182, p. 72 and 73.
[238] Room B-0209, p. 11.
[239] File R-3397-98, decision D-99-11, p. 49.
[240] Part C-ACIG-0102, p. 71.

the balance between a sufficiently long period of application before a new review of the rate of return to achieve the objectives sought while allowing, if the situation so requires, the Claimants to present a request before the end of the period.

[333] The Régie considers that a three-year period of application of the Plaintiffs' rates of return and capital structures ensures this balance. At the end of this period, the Plaintiffs may, if necessary, ask the Régie to review, or not, both their rate of return and their capital structure.

[334] However, in the event that the Claimants are of the opinion that the situation requires a re-examination of their rate of return and their capital structure before the end of this three-year term, they must first submit a request to the Régie on the reasons and conditions justifying such an examination, in a timely manner, before incurring significant costs, in particular with regard to external resources (expert fees, legal fees, etc.).

8. DEFERRED EXPENSE ACCOUNTS

[335] The Claimants file their update of the actual costs241 associated with preparing for the examination of this case and reported to the CFRs.

[336] Énergir asks to accept the terms of disposal of the CFR, which provide that the costs associated with the preparation of the examination of this case be accumulated and carried to its off-base CFR, bearing interest according to the weighted average cost of capital. , until their inclusion in the 2023-2024 tariff file, at the latest.

[337] Gazifère asks to allow the terms of disposal of the CFR, which provide that the costs associated with the preparation of the examination of this case be accumulated and charged to its off-base CFR, bearing interest according to the rate of the debt at short term, for the years 2021 and 2022, until their inclusion in the tariff cases for the years 2023 and 2024 respectively.

241 Exhibit B-0394.

[338] **The Régie upholds Énergir's request concerning the terms and conditions for disposing of the CFR, which provide that the costs associated with preparing for the examination of this case be accumulated and charged to its off-base CFR, bearing interest according to the weighted average cost of capital, until their inclusion in the 2023-2024 tariff case, at the latest.**

[339] **The Régie upholds the Gazifère application relating to the terms and conditions for the disposal of the CFR, which provides that the costs associated with preparing for the examination of this case be accumulated and charged to its off-base CFR, bearing interest at the rate of short-term debt, for the years 2021 and 2022, until their inclusion in the tariff cases for the years 2023 and 2024 respectivel**

9. REQUEST FOR ORDER OF CONFIDENTIAL TREATMENT

[340] Following RFI No. 3 from the Régie242, the Claimants ask in particular to the latter of:

> " *GREAT the request for an order of confidentiality with regard to the annexes to exhibit ÉGI-1, which are identified as exhibits BV-4 to BV-10, BV-12 and BV-13, as well as exhibits EGI-5, EGI-6.3, EGI-7.1 to EGI-7.22, EGI-9, EGI-12, EGI-14.3 to EGI-14.24, EGI-18.1.2, EGI-18.3.1, EGI-18.3.2, EGI-18.3.9, EGI-18.5, EGI-18.5.1 to EGI-18.5.6, EGI-20.4.1 to EGI-20.4.4, EGI-24.2.1, EGI 24.2.4, EGI-24.3 and EGI -18.1.2.*
>
> *PROHIBIT the disclosure, publication and dissemination of the information contained in the appendices to exhibit EGI-1, which are identified as exhibits BV 4 to BV-10, BV-12 and BV-13, as well as exhibits EGI-5 , EGI-6.3, EGI-7.1 to EGI 7.22, EGI-9, EGI-12, EGI-14.3 to EGI-14.24, EGI-18.1.2, EGI-18.3.1, EGI-18.3.2, EGI-18.3. 9, EGI-18.5, EGI-18.5.1 to EGI-18.5.6, EGI-20.4.1 to EGI-20.4.4, EGI 24.2.1, EGI-24.2.4, EGI-24.3 and EGI-18.1.2 until December 31, 2031* ”243.

242 Room B-0330, p. 1.
243 Room B-0331, p. 8.

[341] The Claimants submit affidavits in support of their request for a confidentiality order.

[342] Only ACIG made representations regarding this request for confidentiality. It submits that it has requested access to these documents from the Claimants and that this gave rise to a great deal of discussion and exchange before its experts agreed to sign the modified confidentiality undertaking, the latter judging that the scope of this undertaking was too broad and that the data in question did not, strictly speaking, constitute , confidential information, since it could be obtained by anyone who paid the fees.

[343] ACIG submits that, in its view, the Plaintiffs wish to give “confidential treatment” to the data given the existence of contractual agreements with certain data providers and other copyrights to be respected. However, it wishes to make the Régie aware of the fact that a considerable amount of time has been required on this issue and that it would be necessary to find, possibly, for the future, a way of granting special treatment to this information, without having to be described as "confidential". However, it relies on the Régie on the qualification sought by the Plaintiffs.

Opinion of the Régie

[344] Section 30 of the Act provides the following:

> “ *The Régie may prohibit or restrict the disclosure, publication or distribution of information or documents it indicates, if respect for their confidential nature or the public interest so requires* ”.

[345] This article constitutes an exception to the general rule of the public nature of the proceedings before the Régie. According to this rule, it is incumbent on the party requesting a confidentiality order to prove that the information covered by his request is of a confidential nature which must be respected.

[346] For the purposes of this decision, the Régie takes into consideration the nature of the information covered by the request and the prejudice to which the Plaintiffs would be exposed, according to the affidavits filed in the record.

[347] The Régie lists below the exhibits and information covered by the request for an order of confidentiality and refers to the affidavits concerned, as well as the duration requested for the confidential treatment.

TABLE 10

EXHIBIT OR INFORMATION SUBJECT TO A REQUEST FOR AN ORDER OF CONFIDENTIAL TREATMENT

Part or information making the subject of a request treatment prescription confidential	**Board Rating**	**Declaration under oath**	**Due date treatment confidential**
BV-4 parts to BV-10	B-0016 to B-0022	Ms. Barbara Levine, Exhibit B-0031	December 31, 2031
Parts BV-12 and BV-13	B-0023 and B-0024	Ms. Barbara Levine, Exhibit B-0031	December 31, 2031
Exhibit EGI-18.1.2.	B-0211	Mrs. Odile Poupart (B-0214) and Me Fadi Amine (B-0213)	December 31, 2031
Parts EGI-5, EGI 6.3, EGI-7.1 to EGI 7.22, EGI-9, EGI 12, EGI-14.3 to EGI 14.24, EGI-18.3.1, EGI-18.3.2, EGI 18.3.9, EGI-18.5, EGI-18.5.1 to EGI 18.5.6, EGI-20.4.1 to EGI-20.4.4, EGI 24.2.1, EGI-24.2.4, EGI-24.3.	B-0040, B-0043, B-0046 to B-0067, B-0076, B-0080, B-0108 to B-0129, B-0144, B-0145, B-0152, B-0154, B-0155 to B-0160, B-0194 to B-0197, B-0314, B-0317, B-0318.	Ms. Barbara Levine, Exhibit B-0031	December 31, 2031

[348] **After examining the reasons stated in the affidavits in the third column of Table 10 above, the Régie judges that they justify that the exhibits identified in the first two columns of Table 10 be treated confidentially.**

[349] **The Régie therefore grants the application for a confidentiality order relating to these exhibits and prohibits the disclosure, publication and dissemination of the information they contain, as well as the exhibits themselves, until December 31, 2031.**

[350] **For these reasons,**

The Energy Board:

DETERMINE a rate of return of 8.9% on Énergir's equity for application to the 2022-2023 rate year, starting October 1 , 2022;

APPROVES a deemed capital structure of Énergir consisting of 38.5% equity, 7.5% preferred shares and 54% debt;

DETERMINE a rate of return of 9.05% on Gazifère's equity for application to the 2023 rate year, beginning January 1 , 2023;

APPROVES a deemed capital structure of Gazifère consisting of 40% equity and 60% debt;

APPROVES a deemed capital structure of Intragaz consisting of 46% equity and 54% debt;

DETERMINES that the TRCP of Intragaz will be linked to that of Énergir over the period from May 1 , 2023 to April 30, 2033, so that their rate of return on " *equity* " is equivalent according to their capital structure;

REQUESTS Énergir to file, within a maximum period of two weeks from this decision, the update of the average effective rate of the preferred shares, according to the same methodology for the 2022-2023 tariff year, for the purposes of determining from Intragaz's final TRCP in an upcoming decision;

APPROVES the streamlined method proposed by Intragaz in Exhibit B-0325, which makes it possible to link its TRCP to that of Énergir over the period from May 1 , 2023 to April 30, 2033;

ORDERS that the rule linking the TRCP of Intragaz to that of Énergir is based on the principle used in this decision, namely that the rate of return on *the "equity* " of the two companies be equivalent according to their capital;

ORDERS a three-year enforcement period for the Plaintiffs' rates of return and capital structures;

ORDERS the Claimants, in the event that they are of the opinion that the situation requires a re-examination of the rates of return and the capital structures before the end of the three-year term, to first present a request relating to the reasons and conditions justifying such review before incurring material costs;

WELCOMES Énergir's request relating to the terms and conditions for the disposal of the CFR, which provide that the costs associated with the preparation of the examination of this case be accumulated and charged to its off-base CFR, bearing interest according to the weighted average cost of capital , until their inclusion in the 2023-2024 tariff case, at the latest;

WELCOMES Gazifère's request relating to the terms and conditions of disposal of the CFR, which provide that the costs associated with the preparation of the examination of this file be accumulated and charged to its off-base CFR, bearing interest according to the rate of the short-term debt term, for the years 2021 and 2022, until their inclusion in the tariff cases for the years 2023 and 2024 respectively;

GRANTS the request for an order for confidential treatment of the exhibits presented in Table 10;

PROHIBITS the disclosure, publication and dissemination of the exhibits identified in the first two columns of Table 10 and prohibits the disclosure, publication and dissemination of the information contained therein until December 31, 2031.

Jocelin Dumas

Manager

Lise Duquette

Manager

Esther Falardeau

Manager

Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

IN THE MATTER OF A

GENERAL RATE APPLICATION

FILED BY

NEWFOUNDLAND POWER INC.

DECISION AND ORDER OF THE BOARD

ORDER NO. P.U. 3(2022)

BEFORE:

Darlene Whalen, P. Eng., FEC
Chair and CEO

Dwanda Newman, LL.B.
Vice-Chair

John O'Brien, FCPA, FCA, CISA
Commissioner

Christopher Pike, LL.B.
Commissioner

NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD
NO. P.U. 3(2022)

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 and the *Public Utilities Act*, RSNL 1990, Chapter P-47 as amended, and subordinate regulations;

AND IN THE MATTER OF a general rate application filed by Newfoundland Power Inc. for approval of, *inter alia*, rates to be charged to its customers for 2022 and 2023.

BEFORE:

Darlene Whalen, P. Eng., FEC
Chair and CEO

Dwanda Newman, LL.B.
Vice-Chair

John O'Brien, FCPA, FCA, CISA
Commissioner

Christopher Pike, LL.B.
Commissioner

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1.0 APPLICATION AND PROCEEDING

1.1 Application

Newfoundland Power Inc. ("Newfoundland Power") filed a general rate application with the Board of Commissioners of Public Utilities (the "Board") on May 27, 2021 requesting approval of, among other things, an overall average increase in current electricity rates of 0.8% as of March 1, 2022 for the supply of power and energy to its customers (the "Application").[1]

In the Application Newfoundland Power proposed that the Board approve:

1. rates, tolls and charges and rules and regulations governing service, to be effective for all service provided on and after March 1, 2022, which result in an overall average increase in current customer rates of 0.8%;
2. a rate of return on average rate base for 2022 of 7.19% in a range of 7.01% to 7.37% and for 2023 of 6.97% in a range of 6.79% to 7.15%;
3. a forecast average rate base for 2022 of $1,239,558,000 and for 2023 of $1,289,405,000;
4. a forecast revenue requirement from customer rates for 2022 of $715,364,000 and for 2023 of $712,803,000; and
5. the continued suspension of the automatic adjustment formula for setting the allowed rate of return on average rate base for Newfoundland Power in years subsequent to 2023.

The Application also included proposals for Newfoundland Power's calculation of depreciation expense and general expenses capitalized ("GEC") as well as proposals related to amortizations and recovery of customer Conservation Demand Management ("CDM") and electrification costs, Board and Consumer Advocate costs related to the Application, and the forecast 2022 revenue shortfall.

1.2 Application Process

Notice of the Application and pre-hearing conference was published in newspapers throughout the province beginning on June 12, 2021.

The pre-hearing conference was held on July 6, 2021. In Order No. P.U. 26(2021) the Board identified intervenors, established procedural rules and set the schedule for the proceeding.

Registered intervenors for the proceeding were the Government appointed Consumer Advocate, Dennis Browne, QC (the "Consumer Advocate"), represented by Stephen Fitzgerald, and Newfoundland and Labrador Hydro ("Hydro"), represented by Shirley Walsh. Newfoundland Power was represented by Liam O'Brien, Dominic Foley and Lindsay Hollett. The Board was represented by Maureen Greene, QC, Board Hearing Counsel, and Jacqueline Glynn, Legal Counsel, with assistance from Cheryl Blundon, Board Secretary.

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[1] In Order No. P.U. 2(2019) the Board ordered Newfoundland Power to file its next general rate application no later than June 1, 2021.

The Application was filed with comprehensive supporting evidence which included professional and expert reports. The expert evidence included a report *Cost of Capital*, prepared by James Coyne of Concentric Energy Advisors, Inc., ("Coyne Report") and a report *2019 Depreciation Study – Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2019*, prepared by Gannett Fleming Valuation and Rate Consultants, LLC ("2019 Depreciation Study").[2]

On September 28, 2021 the Board's financial consultants, Grant Thornton LLP ("Grant Thornton") filed a report with respect to its review of Newfoundland Power's pre-filed evidence ("Grant Thornton Report").[3]

On September 28, 2021 the Consumer Advocate filed a report *Fair Return for Newfoundland Power (NP)* prepared by Laurence Booth of the Rotman School of Management, University of Toronto ("Booth Report").

On November 6, 2021 notice of the hearing was published, inviting participation of interested parties or organizations.[4] The hearing was scheduled to begin on November 23, 2021.

On November 9, 2021 Newfoundland Power filed a report, *Executive Compensation Review*, prepared by Wiclif Ma of Korn Ferry.

A total of 507 Requests for Information ("RFIs") were filed and answered in the proceeding.

1.3 Settlement and Hearing

The Board set aside November 1-5, 2021 for settlement discussions, facilitated by Board Hearing Counsel. On November 23, 2021, at the start of the oral public hearing, a settlement agreement between Newfoundland Power, the Consumer Advocate, Hydro and Board Hearing Counsel was filed (the "Settlement Agreement"). The Settlement Agreement stated that it disposed of all of the issues arising from the Application and specifically addressed a number of issues, including operating costs, forecasting, depreciation, certain amortizations, revenue requirements and return on rate base. The parties advised at the hearing that, as the Settlement Agreement addressed all of the items in the Application, they did not intend to present evidence, examine, cross-examine or present argument beyond that which is reasonably necessary to assist the Board. The hearing was adjourned.

1.4 Amended Application

On December 7, 2021 Newfoundland Power filed an amended application (the "Amended Application") to reflect the agreement of the parties as set out in a Settlement Agreement. The Amended Application proposed approval of:

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[2] Application, Volume 3.
[3] Grant Thornton's annual review of Newfoundland Power for 2020 was placed on the record on October 8, 2021.
[4] The Board received three emails objecting to the proposed rate increase. No other comments or submissions were received.

i) rates, tolls and charges and rules and regulations governing service, to be effective for all service provided on and after March 1, 2022, which result in an overall average decrease in current customer rates of 1.1%;
ii) a rate of return on average rate base for 2022 of 6.61% in a range of 6.43% to 6.79% and for 2023 of 6.39% in a range of 6.21% to 6.57%;
iii) a forecast average rate base for 2022 of $1,239,085,000 and for 2023 of $1,287,450,000;
iv) a forecast revenue requirement from customer rates for 2022 of $704,861,000 and for 2023 of $699,245,000; and
v) the continued suspension of the use of an automatic adjustment formula for setting the allowed rate of return for Newfoundland Power.

The Amended Application also included changes to a number of Application proposals to reflect the Settlement Agreement, including adjustments to the calculation of depreciation expense, GEC and 2022 and 2023 operating expenses, as well as account definition amendments and changes to proposed amortizations and recoveries.

On January 17, 2022 Grant Thornton filed a report of its findings with respect to its review of the Amended Application ("Grant Thornton Amended Application Report"). The report confirmed that the revised forecast average rate base, the rate of return on average rate base and the revised forecast test year revenue requirement for 2022 and 2023 to be recovered in customer rates appropriately incorporate the impact of the Settlement Agreement.[5]

2.0 BOARD DECISIONS

In considering the Amended Application the Board must be satisfied that the proposals are reasonable and consistent with the existing regulatory framework and legislation, with particular reference to the power policy of the province as set out in section 3 of the *Electrical Power Control Act*, *1994*, SNL 1994, Chapter E-5.1 (the "*EPCA*").

The Amended Application reflects the recommendation of the parties as set out in the Settlement Agreement for the resolution of all issues arising out of the Application. In considering the Settlement Agreement the Board must be satisfied that the proposals represent a reasonable balance between the interests of the utility and customers considering, among other things, the requirement for Newfoundland Power to deliver reasonable least-cost reliable electricity to customers and for Newfoundland Power to have the opportunity to earn a just and reasonable return. The Board extends its appreciation to the parties and their counsel for their participation in the comprehensive negotiation process and in arriving at the Settlement Agreement.

The Board's findings on the Amended Application, including the Settlement Agreement proposals, are discussed in the following sections.

[5] Grant Thornton Amended Application Report, page 11.

2.1 Capital Structure and Return on Equity for Rate Setting

The Application proposed, for rate setting purposes, a return on equity for the 2022 and 2023 test years of 9.8%, with a deemed common equity ratio of 45%.[6]

Grant Thornton reviewed the calculations of the components of capital structure, average common equity and return on average common equity, including verification of the data and methodology used. Based on its review Grant Thornton confirmed that the calculation of the proposed capital structure for 2022 and 2023 is consistent with Order No. P.U. 2(2019) and that no discrepancies were noted in the calculations of the forecast and proposed rate of return on average common equity for 2021, 2022 and 2023.[7]

The parties agreed in the Settlement Agreement that the capital structure as proposed in the Application should be approved for rate setting purposes and that the rate of return on common equity to be used in determining a just and reasonable return on rate base for 2022 and 2023 should be 8.5%.[8]

The Amended Application proposed, for rate setting purposes, a return on equity for the 2022 and 2023 test years of 8.5%, with a deemed common equity ratio of 45%.[9]

As a part of its review of the Amended Application Grant Thornton calculated that, as a result of the change in return on common equity from 9.8% to 8.5% pursuant to the Settlement Agreement, the return on rate base in the test year revenue requirement decreased by $7,280,000 for 2022 and $7,569,000 for 2023.[10]

In determining whether a rate of return on common equity of 8.5% and common equity ratio of 45% as recommended in the Settlement Agreement and proposed in the Amended Application should be accepted for use in setting Newfoundland Power's 2022 and 2023 rates the Board must consider whether it would provide Newfoundland Power the opportunity to earn a just and reasonable return while providing for the provision of least-cost reliable service.[11]

The Board notes that the rate of return on common equity of 8.5% and common equity ratio of 45% recommended by the parties in the Settlement Agreement and proposed in the Amended Application are the same as were used in setting Newfoundland Power's rates in its last two general rate applications.[12] The recommended rate of return on common equity and common equity ratio for setting Newfoundland Power's 2022 and 2023 test year rates are within the range of the recommendations of the cost of capital experts in this proceeding. According to Mr. Coyne, Newfoundland Power's required cost of equity is 9.8% and a common equity ratio of 45% remains reasonable while Dr. Booth recommended return on equity of 7.50% with a common equity ratio

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[6] Application, Volume 1, page 3-16.
[7] Grant Thornton Report, pages 13-14.
[8] Settlement Agreement, page 3.
[9] Amended Application, page 3.
[10] Grant Thornton Amended Application Report, pages 4 and 5.
[11] Section 80 of the *Public Utilities Act* and sections 3 and 4 of the *EPCA*.
[12] Order Nos. P.U. 18(2016) and P.U. 2(2019).

of 40%.[13] Both Dr. Booth, the Consumer Advocate's expert, and Mr. Coyne, Newfoundland Power's expert, agree that there has not been a material change in Newfoundland Power's business risk since 2018.[14] In terms of the economic and financial conditions Dr. Booth believes that the conditions in 2021 were in many respects similar to 2016 and 2018, although according to Mr. Coyne there are indications that Newfoundland Power's cost of equity is higher than was authorized by the Board in Newfoundland Power's last general rate application.[15] The Board notes that, according to Mr. Coyne, the average return on equity allowed for Canadian investor-owned electric utilities in 2021 was approximately 8.87%.[16]

The Board notes that Newfoundland Power has maintained a solid financial profile and investment grade credit rating from both Moody's Investors Service ("Moody's") and DBRS Morningstar ("DBRS") and this has contributed to its continued access to capital markets on reasonable terms.[17] According to Dr. Booth Newfoundland Power's bond ratings from Moody's and DBRS are higher than normal for a regulated Canadian utility.[18] Both Moody's and DBRS recognize Newfoundland Power's longstanding 45% common equity component of its capital structure as a key credit strength.[19] The Board notes that, if the rate of return on common equity of 8.5% and deemed common equity component of 45% recommended in the Settlement Agreement are accepted for use in setting Newfoundland Power's 2022 and 2023 test year rates, Newfoundland Power's credit metrics would meet or exceed the expectations of the credit rating agencies, and the pro forma earnings test interest coverage metric used by Newfoundland Power when issuing First Mortgage Bonds would exceed the requirement in its Deed of Trust and Mortgage.[20]

Based on the evidence, including the reports of the experts and the credit rating agencies, and considering the agreement of the parties, the Board is satisfied that a rate of return on common equity for Newfoundland Power for rate setting purposes for 2022 and 2023 of 8.5% with a common equity ratio of no greater than 45% will provide Newfoundland Power with the opportunity to earn a just and reasonable return on rate base consistent with the fair return principle and the provision of least-cost reliable service.

The Board accepts the Settlement Agreement recommendation and the Amended Application proposal that, for 2022 and 2023, a rate of return on common equity of 8.5%, with a deemed common equity component of 45%, should be used in setting the allowed rate of return on rate base for the 2022 and 2023 test years.

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[13] Coyne Report, page 81; Booth Report, page 98.
[14] Coyne Report, pages 67 and 79; Booth Report, page 51.
[15] Booth Report, page 35, Coyne Report, page28.
[16] Coyne Report, page 49.
[17] PUB-NP-030, page 3.
[18] Booth Report, page 95.
[19] PUB-NP-030, page 2.
[20] PUB-NP-029; PUB-NP-030; PUB-NP-031; Application, Exhibit 4, *Moody's Credit Rating Report*, November 16, 2020 and *DBRS Rating Report*, October 19, 2020; *DBRS Rating Report*, October 19, 2021, filed by Newfoundland Power in correspondence dated November 9, 2021.

2.2 Customer, Energy and Demand Forecast

The Customer, Energy and Demand forecast is the foundation of Newfoundland Power's planning forecast and a key input in developing estimates of capital and operating expenditures. The Application included a Customer, Energy and Demand Forecast which set out the assumptions and inputs used in developing Newfoundland Power`s customer and energy sales forecast for 2021-2023 and which forecasts:

i) an increase in the number of customers by 0.4% in each of 2021 and 2022, and by 0.3% in 2023;

ii) a decrease in energy sales of 0.2% in 2021, 0.4% in 2022, and 0.7% in 2023; and

iii) an increase in demand of 3.9% in 2021, no change in 2022, and a decrease of 0.7% in 2023.[21]

Grant Thornton reviewed the Customer, Energy and Demand Forecast and determined that the overall forecast methodology used by Newfoundland Power is consistent with the 2019/2020 general rate application. Grant Thornton noted that the current forecast period includes additional assumptions regarding the market penetration of heat pumps and the economic impacts of COVID-19. Grant Thornton reviewed the underlying assumptions based on supporting evidence provided by Newfoundland Power and found no exceptions.[22]

The Settlement Agreement acknowledged that there is considerable uncertainty in the load forecasting owing to the Muskrat Falls Project, government rate mitigation plans and COVID-19 which is expected to continue into the 2023 test year. The Settlement Agreement recommended that the 2022 and 2023 Customer, Energy and Demand Forecast as proposed in the Application should be approved and that it not be revised for price elasticity effects following the issuance of a final order of the Board on the Application. The Settlement Agreement also stated that Newfoundland Power would conduct a Load Research Study and a Retail Rate Design Review, with a detailed framework for each, including a cost estimate, to be provided to the parties in 2022 for input. The parties agreed that a deferral account will be created to recover the costs incurred to conduct the studies with the amortization of the deferral account balance to be determined in Newfoundland Power's next general rate application.[23]

The Amended Application recommended approval of the 2022 and 2023 Customer, Energy and Demand Forecast proposed in the Application, including no revision for price elasticity effects following the Board's final order, as well as approval of the creation of a deferral account to recover the costs incurred to conduct the Load Research Study and a Retail Rate Design Review.

The Board is satisfied that the Customer, Energy and Demand Forecast proposed in the Application and agreed to in the Settlement Agreement is reasonable and should be accepted for determining the 2022 and 2023 test year load forecasts and revenue requirements. As set out in the Settlement Agreement the test year load forecast will not be revised for elasticity effects following the Board's

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[21] Application, Volume 2, Tab 3: *Customer, Energy and Demand Forecast, May 2021*; Application, Volume 1, pages 5-1 to 5-6. The number of customers served by Newfoundland Power is forecast at 272,253 in 2022 and 273,165 in 2023.
[22] Grant Thornton Report, page 6.
[23] Settlement Agreement, page 3.

order on the Amended Application. The Board also accepts the agreement of the parties with respect to the Load Research Study and a Retail Rate Design review to be undertaken by Newfoundland Power.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the 2022 and 2023 Customer, Energy and Demand Forecast, including that there will be no revision for price elasticity effects following the final order of the Board.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals with respect to a Load Research Study and a Retail Rate Design Review and will direct Newfoundland Power to conduct the study and review, with the costs to be charged to a deferral account.

2.3 Regulatory Accounting and Amortizations

The Application included proposals for minor changes to the calculation of GEC to account for changes in Newfoundland Power's operations and also to remove pension costs from GEC to be capitalized by way of a labour loader. The Application also proposed to increase the amortization period for CDM program costs incurred after January 1, 2021 from seven to ten years and to amortize electrification program costs over ten years.

2.3.1 General Expenses Capitalized

On April 30, 2020 the Board requested Newfoundland Power provide a report describing its capitalization practices relating to capital asset additions, including a jurisdictional scan of capitalization practices used by other utilities across Canada.[24] In February 2021 the Board requested that Newfoundland Power include with its next general rate application a review of its methodology and cost ratios used to determine GEC, an explanation as to why pension costs are included in its GEC calculation, and the impact on revenue requirement and customer rates if the pension costs were charged directly to capital projects by way of a labour loader.

The Application included Newfoundland Power's review with respect to GEC which determined that the use of the incremental cost method for the calculation of GEC continues to be reasonable on the basis that i) it results in relatively stable allocations, ii) limits the allocation of general expenses to only those necessary to bring an asset into service and recovers those costs over the life of the asset, and iii) provides overall capitalization amounts that are reasonably consistent with other Canadian utilities.[25] Newfoundland Power concluded that, excluding pension costs, its methodology for calculating GEC is consistent with established regulatory principles of the Board and sound public utility practice.

The Application proposed changes to the calculation of GEC to remove general expenses for printing services and add general expenses for information systems. Changes to the existing cost ratios are also proposed to account for changes in Newfoundland Power's operations since the

[24] The report was submitted on August 14, 2020 and included with the Application in Volume 2, Tab 6, Attachment 1.
[25] Application, Volume 1, page 3-48.

matter was last considered by the Board in 1999. These changes to the calculation of GEC are proposed to be effective January 1, 2023 and would decrease 2023 revenue requirement by approximately $0.1 million.

The Application also proposed that, effective January 1, 2023, pension costs be removed from the GEC calculation and be directly charged to capital projects by way of a labour loader. This proposed change will increase the 2023 forecast revenue requirement by $1,427,000 due to income tax effects. According to the Application allocation of pension costs directly to capital projects is consistent with sound public utility practice and Newfoundland Power's current treatment of Other Post-Employment Benefits (OPEB) costs.[26] The Application also noted that the income tax effects of this proposed change in allocation will reverse over time, resulting in a decrease in revenue requirements in subsequent years such that, ultimately, there would be no impact on the total revenue requirement recovered through customer rates over the service lives of the related capital assets.

Grant Thornton reviewed the GEC methodology set out in the Application and found that the incremental method is an acceptable methodology to determine the GEC, is supported by the jurisdictional survey results filed with the Application, and that the GEC results have been consistent year over year.[27] Grant Thornton concluded that the allocation of pension costs directly to capital projects by way of a labour loader is also consistent with the survey results and that the income tax effects in relation to the pension cost allocation are appropriate.[28]

The Settlement Agreement recommended that the proposed revisions to Newfoundland Power's GEC calculation be approved, effective January 1, 2023, subject to using a deferral account to offset the impact of the proposed change in capitalizing pension costs, with amortization of the recovery of $1,427,000 over a 5-year period commencing January 1, 2023.[29]

The Amended Application requested approval of the revisions to the proposed GEC calculation as set out in the Application, amended to reflect the Settlement Agreement recommendations.

The Board notes the GEC methodology proposed in the Amended Application is consistent with prior practices of Newfoundland Power and offers stability in GEC allocations. According to the evidence filed with the Application all proposed general expenses in the GEC calculation are consistent with the definition of Capitalized Overheads in the Federal Energy Regulatory Commission ("FERC") System of Accounts.[30] The removal of pension costs from the GEC calculation and charging these costs directly to capital projects is also consistent with sound public utility practice and would result in a more accurate allocation of general expenses to capital projects. The use of a deferral account to defer the increase in revenue requirement associated with the removal of the pension costs from GEC calculation, as recommended by the Settlement Agreement, will mitigate the impact of this change on customer rates.

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[26] Application, Volume 1, page 3-52.
[27] Grant Thornton Report, page 47/4-8.
[28] Grant Thornton Report, page 50/34-37.
[29] Settlement Agreement, page 4.
[30] Application, Volume 2, Tab 6: *Review of General Expenses Capitalized*, Appendix A.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals with respect to the revisions to Newfoundland Power's GEC calculation and will approve the changes, effective January 1, 2023, as well as the amortization of the associated increase in revenue requirement of $1,427,000 over a five-year period.

2.3.2 Recovery of CDM and Electrification Program Costs

In Order No. P.U. 13(2013) the Board approved a CDM Cost Deferral Account and the amortization of CDM program costs over a seven-year period through the Rate Stabilization Clause. The Application proposed to increase the amortization of CDM program costs incurred commencing January 1, 2021 from seven to ten years on the basis that this amortization period generally corresponds with the average useful life of the technologies captured by CDM programs. This increase in amortization would reduce revenue requirements in 2022 and 2023 by approximately $280,000 and $587,000 respectively.[31] The Application also included a proposed revision to Clause II.7 of the Rate Stabilization Clause to reflect the proposed change in the amortization period.

The Settlement Agreement recommended approval of Newfoundland Power's proposed increase in the amortization period from seven to ten years for customer CDM program costs incurred after January 1, 2021 as well as the corresponding amendment to Clause II.7 of the Rate Stabilization Clause, and also recommended that the same ten-year period be used for CDM program costs incurred prior to January 1, 2021.

The Board is satisfied the amortization period for CDM program costs should be increased from seven years to ten years. The evidence shows that this practice is consistent with current public utility practice and the change will result in lower revenue requirements for 2022 and 2023 associated with Newfoundland Power's CDM programs.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the increase in the amortization period for customer CDM program costs from seven years to ten years, commencing January 1, 2021 for both historical balances and annual charges, and will approve the associated amendments to Clause II.7 of the Rate Stabilization Clause.

The Application also included a proposed Electrification Cost Deferral Account to provide for the deferral of costs incurred in implementing its Customer Electrification Portfolio. The account would also be credited with any government funding received related to electrification programs and any revenues associated with the operation of company-owned charging stations. The existing Clause II.9 of the Rate Stabilization Clause is proposed to be replaced with a new clause to allow for the Electrification Cost Recovery Transfer from the Electrification Cost Deferral Account, with these costs also proposed to be amortized over a ten-year period.

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[31] In its 2021 Electrification, Conservation and Demand Management Application filed with the Board on December 16, 2020 Newfoundland Power proposed approval of an Electrification Cost Deferral Account, with the amortization period for electrification program costs to be determined as part of the next general rate application.[31] Application, Volume 1, pages C 3-54 and 3-55.

The Settlement Agreement recommended that all electrification infrastructure and program costs be removed from the proposed 2022 and 2023 revenue requirement and rate base. The Settlement Agreement also proposed an amended definition of the proposed Electrification Cost Deferral Account to include costs associated with approved electric vehicle charging infrastructure capital costs until otherwise ordered by the Board and any funding received from Government related to electric vehicle charging infrastructure. The amended definition also states that the account will not be included in Newfoundland Power's calculation of rate base until otherwise ordered by the Board. [32]

The Amended Application proposed approval of the amended Electrification Cost Deferral Account as set out in the Settlement Agreement and the proposal in the Application to replace Clause II.9 of the Rate Stabilization Clause with an amended clause to allow for the amortization of electrification program costs over a ten-year period.

In its review of the Amended Application Grant Thornton requested Newfoundland Power to confirm that it is seeking approval of the proposed Clause II.9 and whether any electrification costs are proposed to be recovered from the Rate Stabilization Account in 2022 and 2023. Newfoundland Power provided the following response:

> As the electrification cost deferral account did not exist in 2021, there were no charges to the account in 2021. Therefore, there would be no transfer from the account to the Rate Stabilization Account in 2022.
>
> If the electrification deferral account is approved in 2022 …there will be transfers to the account in 2022 and thus recovery through the RSA in the 2023 transfer (1/10th of the 2022 balance). It would only be associated with electrification infrastructure and program related costs in accordance with Board orders, such as the EV charger supplemental capital expenditures approved by the Board in Order No. P.U. 30 (2021), per the account definition.[33]

Grant Thornton concluded that they were not aware if the recovery of costs charged annually to the Electrification Cost Deferral Account over a ten-year period was intended to be included in the Settlement Agreement as it was not specifically addressed.

In Order No. P.U. 30(2021) the Board approved the proposed supplemental 2021 capital expenditures for the deployment of electric vehicle charging stations in the amount of approximately $1.5 million with the recovery of these expenditures to be addressed in a subsequent order of the Board. The Board has allowed for the deferral of these costs with the question of how these approved capital expenditures will be recovered from customers to be addressed in a subsequent order of the Board. The Board is satisfied that the Electrification Cost Deferral Account proposed in the Amended Application should be approved to allow for the deferral of electrification program costs, including charging infrastructure capital costs, until the Board has made a determination on the 2021 Electrification, Conservation and Demand Management Application. The Board notes that the amended Electrification Cost Deferral Account definition

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[32] The Amended Electrification Cost Deferral Account Definition was attached as Schedule "A" to the Settlement Agreement.
[33] Grant Thornton Amended Application Report, page 10.

included in the Settlement Agreement and the Amended Application, states that the "recovery of annual amortizations of costs in this account shall be through the Company's Rate Stabilization Clause or as otherwise ordered by the Board."[34] With respect to the proposed amortization of the costs over a ten-year period through the Rate Stabilization Clause the Board is not satisfied that this proposal should be approved at this time but should be considered as part of the 2021 Electrification, Conservation and Demand Management Application.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals with respect to the establishment of an Electrification Cost Deferral Account and will approve the account definition as proposed but will not approve the proposed amendment to Clause II.9 of the Rate Stabilization Clause at this time.

2.4 Operating Costs

The Application proposed approval of forecast operating costs to be included in revenue requirement of $67,495,000 for 2022 and $73,226,000 for 2023.[35]

Grant Thornton reviewed the operating cost forecasts for 2022 and 2023 in the Application and noted the key variances for each year between 2019 actual and 2023 forecast. Grant Thornton concluded that, based on their review and analysis, nothing had come to their attention to indicate that the forecast 2021, 2022 and 2023 operating costs are unreasonable on an overall basis.[36]

The Settlement Agreement recommended that the 2022 and 2023 operating costs as proposed in the Application be approved with, the following amendments:

i) Effective for the fiscal year ended December 31, 2022, only 50% of expenses associated with the cash flow component of the corporate target of Newfoundland Power's short-term incentive program will be recovered in customer rates.
ii) All electrification infrastructure and programming costs will be removed from the proposed revenue requirement and rate base for 2022 and 2023. Electrification infrastructure costs approved by the Board will be charged to the Electrification Cost Deferral Account proposed in Schedule A of the Settlement Agreement.
iii) Operating costs for 2023 will be reduced by $300,000 to reflect operating efficiencies.[37]

A number of other Settlement Agreement proposals also affect the operating costs to be included in revenue requirement:

i) Actual hearing costs for the Board and the Consumer Advocate will be recovered through the Rate Stabilization Account instead of being amortized.
ii) The amortization period for customer CDM program costs incurred before and after January 1, 2021 will be increased from seven to ten years.

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[34] Amended Application, Exhibit 13.
[35] Application Volume 1, page 4-4. Forecast operating costs for 2022 include proposed hearing cost recovery of $294,000, new electrification program amortization of $134,000 and a decrease in existing CDM program amortization of $280,000. Forecast operating costs for 2023 include $353,000 for hearing costs, electrification amortization of $435,000, a decrease of $587,000 in existing CDM programming amortizations and an increase of $3,289,000 for changes in general expenses capitalized proposed in the Application to be effective January 1, 2023.
[36] Grant Thornton Report, pages 17-19.
[37] Settlement Agreement, pages 2 and 3.

The Amended Application proposed approval of forecast operating costs to be included in revenue requirement of $64,996,000 for 2022 and $70,725,000 for 2023.[38]

Grant Thornton confirmed that, consistent with the Settlement Agreement, the revised 2022 and 2023 operating cost reductions of $2,499,000 and $2,501,000 include the impact of the Settlement Agreement proposals set out above.[39]

The Board notes that Grant Thornton has confirmed reductions in operating costs as a result of the Settlement Agreement of approximately $2.5 million for both 2022 and 2023. The lower operating costs proposed in the Amended Application reflect the agreement of the parties to change the amortization period for CDM program costs incurred before January 1, 2021, which has been accepted by the Board. These operating costs also reflect the removal of the amortizations related to electrification programming costs. This is consistent with the direction of the Board and the agreement of the parties that all costs associated with electrification infrastructure and programming be removed from the proposed revenue requirement and rate base. Based on the evidence the recommended reduction in short-term incentive costs for the 2022 and 2023 test years, the efficiency reduction in operating costs for the 2023 test year, and the recovery of actual hearing costs through the Rate Stabilization Account also reduce the operating costs for the 2022 and 2023 test years.

The Board is satisfied that the total operating costs for the 2022 and 2023 test years proposed in the Amended Application reflect the recommendations of the parties in the Settlement Agreement and the associated reductions in operating costs are reasonable and will not adversely affect service or reliability.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the 2022 and 2023 operating costs to be used in calculating the 2022 test year revenue requirement and the 2023 test year revenue requirement.

2.5 Depreciation

The Application proposed approval of the calculation of forecast depreciation expense of $70,956,000 for 2022 and $75,252,000 for 2023 reflecting the methodology and depreciation rates set out in the 2019 Depreciation Study. The forecast depreciation expense for 2022 and 2023 includes recovery of an accumulated reserve variance of approximately $1.9 million a year over the average remaining service life of the affected asset classes as recommended in the 2019

[38] Amended Application, Exhibit 7.

[39] Grant Thornton Amended Application Report, pages 3 and 4.The decrease in the 2022 operating costs include a reduction in the amortization of hearing costs of $294,000, a reduction of $26,000 in short-term incentive program costs, a reduction of the amortization of CDM costs of $2,045,000 related to the forecast and historical costs being amortized over 10 years, and a reduction in the amortization of electrification costs of $134,000 as a result of the removal of these costs from test year forecast. The decrease in the 2023 operating costs include a reduction in the amortization of hearing costs of $353,000, a reduction of $27,000 in short-term incentive program costs, a reduction of the amortization of CDM costs of $1,386,000 related to the forecast and historical costs being amortized over 10 years, and a reduction in the amortization of electrification costs of $435,000 as a result of the removal of these costs from test year forecast, and a reduction of $300,000 in operating costs to reflect operating efficiencies for 2023.

Depreciation Study.[40] On August 24, 2021 Newfoundland Power advised that an error had been identified in the calculation of the depreciation expenses and requested that the corrections be incorporated in the compliance application following the Board's order.[41] The Board granted the request.[42]

Grant Thornton reviewed Newfoundland Power's forecast depreciation expense for 2022 and 2023 and concluded that, with the exception of the errors identified, the depreciation rates used to calculate the forecast depreciation expenses for 2022 and 2023 agree to those recommended in the 2019 Depreciation Study and Newfoundland Power's pre-filed evidence.[43]

The Settlement Agreement recommended that the Board approve the forecast depreciation expense for 2022 and 2023 in accordance with the methodology and rates outlined in the 2019 Depreciation Study, subject to:

i) correction for the appropriate service life of the Customer Information System (from 10 to 18 years); and
ii) removal of electric vehicle charging stations from plant investment.[44]

In its review of the Amended Application Grant Thornton noted that the forecast depreciation expense decreased by $24,000 for 2022 as a result of the removal of electric vehicle charging stations from plant investment and by $794,000 for 2023 as a result of correcting the appropriate service life of the Customer Information System and the removal of electric vehicle charging stations from plant investment. Grant Thornton concluded that appropriate evidence was provided to support the revisions as a result of the Settlement Agreement.[45]

The Board is satisfied that the proposed depreciation expense proposed in the Amended Application reflects the recommendations of the parties in the Settlement Agreement. The Board notes that the proposed changes in the individual depreciation rates for differing asset classes recommended in the 2019 Depreciation Study result in lower forecast depreciation expense for 2022 and 2023.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the calculation of depreciation expense for 2022 and 2023.

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[40] Application, Volume 1, pages 3-7 and 3-8.
[41] Newfoundland Power advised that the proposed depreciation expense for the Customer Information System assets reflected depreciation for a shorter than the intended service life (10 years rather than 18) and that the EV Charging Stations were depreciated over a longer than intended service life (30 years rather than 10).
[42] Letter from Board to Newfoundland Power dated August 25, 2021.
[43] Grant Thornton Report, page 36.
[44] Settlement Agreement, page 2.
[45] Grant Thornton Amended Application Report, pages 3-5.

2.6 Other Proposed Deferrals

2.6.1 Hearing Costs Recovery

The Application proposed that the estimated $1.0 million in costs to be billed to Newfoundland Power for the costs of the Board and the Consumer Advocate as a result of the Application be recovered in customer rates over a 34-month period commencing on March 1, 2022 and ending December 31, 2024. The Application proposed that any difference between actual and estimated Board and Consumer Advocate costs for rate setting purposes be rebated or recovered through the Rate Stabilization Account.[46]

The Settlement Agreement recommended that actual Board and Consumer Advocate costs related to the Application be recovered through the Rate Stabilization Account.[47]

The Board notes that the recovery of actual Board and Consumer Advocate costs through the Rate Stabilization Account will result in forecast hearing costs being removed from the revenue requirement for 2022 and 2023 and that the actual hearing costs, which will be lower as the matter was settled, will be recovered through the Rate Stabilization Account.

The Board accepts the Settlement Agreement recommendation and the Amended Application proposal in relation to the recovery of actual Board and Consumer Advocate costs through the Rate Stabilization Account, over a 34-month period, commencing on March 1, 2022 and ending December 31, 2024.

2.6.2 Forecast Revenue Shortfall

The Application proposed to amortize a 2022 revenue shortfall in the amount of $1,262,000, associated with the implementation of customer rates on March 1, 2022, over a 34-month period commencing on March 1, 2022 and ending December 31, 2024. The Application stated that the proposed treatment of the 2022 revenue shortfall is consistent with past practice of the Board.[48]

The Settlement Agreement recommended that the amortization of a forecast 2022 revenue shortfall of approximately $930,000 over a 34-month period, commencing March 1, 2022 and ending December 31, 2024, should be approved as modified by any relevant Board orders issued subsequent to the filing of the Application.[49]

Grant Thornton recalculated the 2022 forecast revenue shortfall of $930,000 as set in the Amended Application and the amortization of the 2022 revenue shortfall included in the 2022 and 2023 revenue requirement.[50] Grant Thornton, in its review of the Amended Application, noted that the changes in the 2022 revenue shortfall were primarily due to a reduction in the return on equity to

[46] Application, Volume 1, page 3-59.
[47] Settlement Agreement, page 4. Clause II.6 allows for the Rate Stabilization Account to be adjusted by any other amount by order of the Board.
[48] Application Volume 1, page 3-59.
[49] Settlement Agreement, page 4. The variance in Application and Settlement Agreement amounts for forecast 2022 revenue shortfall is attributable to revisions for revenue requirement.
[50] Grant Thornton Amended Application Report, page 3, Note 2.

8.5%. Based on its review Grant Thornton concluded that there was appropriate evidence to support the revisions in the Amended Application as a result of the Settlement Agreement.[51]

The Board accepts the Settlement Agreement recommendation and the Amended Application proposal in relation to the approval of the amortization of a forecast revenue shortfall of approximately $930,000 through the Rate Stabilization Account, over a 34-month period, commencing March 1, 2022 and ending December 31, 2024.

2.6.3 Proposed Deferral Accounts

The Amended Application also requests approval of two new deferral accounts as a result of the Settlement Agreement: i) a Load Research and Rate Design Cost Deferral Account; and ii) a Pension Capitalization Cost Deferral Account.[52]

The proposed Load Research and Rate Design Cost Deferral Account will capture the costs associated with a Load Research Study and a Retail Rate Design Study, to be conducted by Newfoundland Power pursuant to the Settlement Agreement.[53]

The Pension Cost Capitalization Deferral Account will capture the costs resulting from the change in capitalizing pension costs from the indirect method via general expenses capitalized to the direct method via a labour loader as of January 1, 2023.[54]

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the establishment of a Load Research and Rate Design Cost Deferral Account and a Pension Capitalization Cost Deferral Account and will approve the account definitions as proposed.

2.7 Forecast Average Rate Base and Rate of Return on Rate Base

The Application proposed: i) a forecast average rate base of $1,239,558,000 for 2022 and $1,289,405,000 for 2023, and ii) a rate of return on average rate base for 2022 of 7.19% in a range of 7.01% to 7.37% and for 2023 of 6.97% in a range of 6.79% to 7.15%.[55] The Application also proposed the continued suspension of the automatic adjustment formula for adjusting the allowed return on rate base for Newfoundland Power on an annual basis.[56]

2.7.1 Forecast Average Rate Base

Grant Thornton reviewed the calculations of forecast average rate base for 2022 and 2023 set out in the Application and confirmed that the proposed average rate base is in accordance with established practice and reflects Newfoundland Power's proposals in the Application with respect

[51] Grant Thornton Amended Application Report, page 11.
[52] Amended Application, Exhibits 15 and 16.
[53] See Section 2.2 of this Order.
[54] See Section 2.3.1 of this Order.
[55] Application Volume 1, page 3.
[56] Application, page 2.

to the change in accounting for GEC, regulatory deferral accounts, the 2019 Depreciation Study and the updated calculations related to the rate base allowances.[57]

The Settlement Agreement recommended that the Board approve a forecast average rate base for 2022 of $1,239,085,000 and 2023 of $1,287,665,000.

The Amended Application proposed approval of a forecast average rate base for 2022 of $1,239,085,000 and for 2023 of $1,287,450,000.[58] In its review of the Amended Application, Grant Thornton requested an explanation for the variation in the 2023 average rate base between the Settlement Agreement and the Amended Application. Newfoundland Power explained that its review to ensure the Amended Application correctly reflected the Settlement Agreement resulted in a reduction of $215,000 in the forecast 2023 average rate base to reflect the removal in 2023 of $460,000 in capital costs related to the Electrification Program.[59] Grant Thornton reviewed the forecast average rate base and concluded that it appropriately incorporates the Settlement Agreement.[60]

The Board is satisfied that the forecast average rate base for 2022 and 2023 proposed in the Amended Application reflects the recommendations in the Settlement Agreement with respect to the changes in plant investment (correction for the appropriate service life in the Customer Information System and removal of Electric Vehicle Charging Stations), changes in cost recovery deferrals and resulting impacts on accumulated deferred income tax and cash working capital allowances.[61]

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the forecast average rate base and will approve a forecast average rate base for 2022 of $1,239,085,000 and for 2023 of $1,287,450,000.

2.7.2 Rate of Return on Average Rate Base

The Application proposed a rate of return on average rate base for 2022 of 7.19% in a range of 7.01% to 7.37% and for 2023 of 6.97% in a range of 6.79% to 7.15%.[62]

Grant Thornton reviewed the calculations of the forecast return on average rate base for 2022 and 2023 set out in the Application and concluded that the forecast return included in the Application was calculated in accordance with established practice and the proposed rate of return on average rate base accurately reflects the proposals in the Application.[63]
The Settlement Agreement recommended that the Board approve a rate of return on average rate base for 2022 of 6.61% in a range of 6.43% to 6.79% and for 2023 of 6.39% in range of 6.21% to 6.57%.[64]

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[57] Grant Thornton Report, pages 10-11.
[58] Amended Application, page 3.
[59] Grant Thornton Amended Application Report, page 9.
[60] Grant Thornton Amended Application Report, page 11.
[61] Grant Thornton Amended Application Report, pages 6-7.
[62] Application, page 3.
[63] Grant Thornton Report, page 12.
[64] Settlement Agreement, page 4.

The Amended Application proposed a rate of return on average rate base for 2022 of 6.61% in a range of 6.43% to 6.79% and for 2023 of 6.39% in range of 6.21% to 6.57%.

The Board notes that the decrease in the forecast return on rate base in the Amended Application is the result of the decrease in the return on common equity from 9.8% as proposed in the Application to 8.5% as recommended in the Settlement Agreement and accepted by the Board. Grant Thornton confirmed the calculation of the average rate base and return on average rate base for 2022 and 2023 set out in the Application and the changes in the forecast average rate base for 2022 and 2023 proposed in the Amended Application as a result of the Settlement Agreement recommendations.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to the rate of return on average rate base and will approve a rate of return on average rate base for 2022 of 6.61%, in a range of 6.43% to 6.79%, and for 2023 of 6.39%, in range of 6.21% to 6.57%.

2.7.3 Automatic Adjustment Formula

The Settlement Agreement recommended that the Board approve the continued suspension of the use of an automatic adjustment formula, as proposed in the Application.

The use of an automatic adjustment formula was approved by the Board in 1998 to determine changes to Newfoundland Power's return on equity between general rate applications based on forecast changes in long-term Canada bond yields. The use of the formula was suspended in 2013 on the basis of abnormally low bond yields which raised concerns about the operation of the formula in establishing a fair return for Newfoundland Power. The formula has been suspended since that time. In the Application Newfoundland Power noted that long-term Canada bond yields are still very low, justifying the continued suspension of the automatic adjustment formula consistent with Canadian regulatory practice.[65]

The Board accepts the Settlement Agreement recommendation and the Amended Application proposal in relation to the continued suspension of the automatic adjustment formula.

2.8 Revenue Requirement

The Application requested approval of a revenue requirement of $715,364,000 for 2022 and $712,803,000 for 2023.[66] Grant Thornton confirmed the inputs and calculations for the proposed 2022 and 2023 revenue requirement to be recovered in customer rates.[67]

The Settlement Agreement recommended that the revenue requirement for 2022 of $704,843,000 and for 2023 of $699,260,000 be approved as modified by any relevant Board orders issued

[65] Application, Volume 1, pages 3-45 to 3-46.
[66] Application, Volume 1, Exhibit 7.
[67] Grant Thornton Report, page 54.

subsequent to the filing of the Application. The Settlement Agreement sets out that the recommended revenue requirement for 2022 and 2023 reflects the following revisions:

a) correction of the calculation of depreciation expense;
b) recovery of expenses associated with the cash flow component of the corporate target of Newfoundland Power's short-term incentive program being capped at 50%;
c) removal of $300,000 from 2023 operating costs;
d) change to the rate of return on common equity to be used in determining a return on rate base for 2022 and 2023;
e) removal of electrification infrastructure and program costs;
f) use of a deferral account to offset the impact of the proposed change in capitalizing pension costs;
g) amortization of a forecast 2022 revenue shortfall; and
h) removal of the estimated Board and Consumer Advocate costs related to the Application.[68]

The Amended Application proposes approval of a revised revenue requirement for 2022 of $704,861,000 and $699,245,000 for 2023.[69] In its review of the Amended Application Grant Thornton requested an explanation for the variations in the 2022 and 2023 forecast revenue requirement between the Settlement Agreement and the Amended Application. Newfoundland Power provided the following explanation:

> Similar to the Compliance Filing of the 2020 GRA, a final quality assurance process was completed on the Amended Application financial forecasts. As a result of this review, a number of minor adjustments were made to ensure the Amended Application correctly reflected the terms of the Settlement Agreement.
>
> The impact of these adjustments is minimal. The result is an increase in revenue requirements of $18,000 in 2022 and reduction in revenue requirements of $15,000 in 2023 compared to the Settlement Agreement forecasts.[70]

Grant Thornton reviewed the revised revenue requirement forecasts for 2022 and 2023 and found that Newfoundland Power's calculations were in accordance with the Settlement Agreement and the Application.[71]

The Board is satisfied that the proposed revenue requirement to be recovered in customer rates set out in the Amended Application reflects the Settlement Agreement proposals and should be approved.

The Board accepts the Settlement Agreement recommendations and the Amended Application proposals in relation to revenue requirement and accepts, for rate setting purposes, a test year revenue requirement of $704,861,000 for 2022 and a test year revenue requirement of $699,245,000 for 2023.

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[68] Settlement Agreement, page 5.
[69] Amended Application, page 4.
[70] Grant Thornton Amended Application Report, page 9.
[71] Grant Thornton Amended Application Report, page 11.

2.9 Rates, Rules and Regulations

The Amended Application proposes a 1.1% average decrease in Newfoundland Power customer rates for each class of service, effective March 1, 2022 as set out in Schedule A of the Amended Application. The Amended Application also proposes approval of Newfoundland Power's rules and regulations.

Grant Thornton confirmed that Newfoundland Power's schedule of rates as set out in Schedule A of the Amended Application incorporates the terms of the Settlement Agreement.[72]

The Board accepts the Amended Application proposals in relation to Newfoundland Power's rates, rules and regulations and will approve the proposed Schedule of Rates to be effective for electrical consumption on and after March 1, 2022, and the proposed Rules and Regulations, to be effective March 1, 2022, with the exception of the proposed changes to Clause II.9 of the Rate Stabilization Clause.

2.10 Next General Rate Application

The Settlement Agreement did not address the matter of the filing of Newfoundland Power's next general application. The Board notes that there is uncertainty in relation to rate mitigation and Muskrat Falls but does not think this uncertainty impacts the requirement for the Board to review Newfoundland Power costs and expenses on the established three-year cycle.

The Board will require Newfoundland Power file its next general rate application no later than June 1, 2024, subject to any further direction of the Board.

2.11 Costs

Newfoundland Power will be required to pay the costs of the Board arising from this Application, including the costs of the Consumer Advocate, pursuant to sections 90(1) and 117(3) of the *Public Utilities Act.*

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[72] Grant Thornton Amended Application Report, page 8.

3.0 BOARD ORDER

IT IS THEREFORE ORDERED THAT:

Rate Base and Rate of Return on Rate Base

1. The forecast average rate base for 2022 of $1,239,085,000 and the forecast average rate base for 2023 of $1,287,450,000 are approved.

2. The rate of return on average rate base for 2022 of 6.61%, in a range of 6.43% to 6.97%, and the rate of return on average rate base for 2023 of 6.39%, in a range of 6.21% to 6.57%, are approved.

3. The use of an automatic adjustment formula shall continue to be suspended until further Order of the Board.

4. Newfoundland Power shall file an application on or before November 15, 2023 for approval of the 2024 forecast average rate base and rate of return on rate base, maintaining the common equity ratio and return on common equity accepted for rate setting in this Order.

5. Newfoundland Power shall, unless otherwise directed by the Board, file its next general rate application no later than June 1, 2024.

Depreciation

6. The calculation of depreciation expense, with effect from January 1, 2022 using the depreciation rates and methodology recommended in the 2019 Depreciation Study, as amended, is approved.

Other Regulatory Matters

7. The amortization of a forecast revenue shortfall for 2022 of $930,000 through the Rate Stabilization Account, over a 34-month period commencing March 1, 2022 and ending December 31, 2024, is approved.

8. The amortization of actual hearing costs for the Board and the Consumer Advocate through the Rate Stabilization Account, over a 34-month period commencing on March 1, 2022 and ending December 31, 2024, is approved.

9. The change in the calculation of general expenses capitalized to remove pension costs, effective January 1, 2023, is approved.

10. Newfoundland Power shall conduct a Load Research Study and a Retail Rate Design Review with a detailed framework and cost estimate for each to be filed by December 31, 2022.

11. The increase in the amortization period for customer CDM program costs from seven years to ten years, commencing January 1, 2021 for both historical balances and annual charges, and the associated amendments to Clause II.7 of the Rate Stabilization Clause are approved.

Rates, Rules and Regulations

12. Newfoundland Power's Schedule of Rates, as set out in Schedule A, to be effective for all electrical consumption on and after March 1, 2022, is approved.

13. Newfoundland Power's Rules and Regulations, to be effective on and after March 1, 2022, are approved, with the exception of the proposed changes in relation to Clause II.9 of the Rate Stabilization Clause.

14. Newfoundland Power shall file revised Rules and Regulations to reflect the Board's determinations in this Order.

Deferral Accounts

15. The Pension Capitalization Cost Deferral Account to amortize the forecast revenue requirement increase of $1,427,000 associated with the change in the calculation of general expenses capitalized, as set out in Schedule B, is approved.

16. The Load Research and Rate Design Cost Deferral Account to defer the costs of the Load Research Study and Retail Rate Design Review, as set out in Schedule C, is approved.

17. The Electrification Cost Deferral Account, as set out in Schedule D, is approved.

Costs

18. Newfoundland Power shall pay the costs and expenses of the Board arising from the Application, including the expenses of the Consumer Advocate incurred by the Board.

DATED at St. John's, Newfoundland and Labrador, this 16th day of February, 2022.

Darlene Whalen, P. Eng., FEC
Chair and Chief Executive Officer

Dwanda Newman, LL.B.
Vice-Chair

John O'Brien, FCPA, FCA, CISA
Commissioner

Christopher Pike, LL.B., FCIP
Commissioner

Cheryl Blundon
Board Secretary

NEWFOUNDLAND POWER INC.
RATE #1.1
DOMESTIC SERVICE

Availability:

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

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge:
Not Exceeding 200 Amp Service .... $15.81 per month
Exceeding 200 Amp Service .... $20.81 per month

Energy Charge:
All kilowatt-hours .... @12.381¢ per kWh

Minimum Monthly Charge:
Not Exceeding 200 Amp Service .... $15.81 per month
Exceeding 200 Amp Service .... $20.81 per month

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #1.1S
DOMESTIC SEASONAL - OPTIONAL

Availability:

Available upon request for Service to Customers served under Rate #1.1 Domestic Service who have a minimum of 12 months of uninterrupted billing history at their current Serviced Premises.

Rate:

The Energy Charges provided for in Rate #1.1 Domestic Service Rate shall apply, subject to the following adjustments:

Winter Season Premium Adjustment (Billing months of December through April):
All kilowatt-hours .... @ 0.953¢ per kWh

Non-Winter Season Credit Adjustment (Billing Months of May through November):
All kilowatt-hours .... @ (1.297)¢ per kWh

Special Conditions:

1. An application for Service under this rate option shall constitute a binding contract between the Customer and the Company with an initial term of 12 months commencing the day after the first meter reading date following the request by the Customer, and renewing automatically on the anniversary date thereof for successive 12-month terms.

2. To terminate participation on this rate option on the renewal date, the Customer must notify the Company either in advance of the renewal date or no later than 60 days after the anniversary/renewal date. When acceptable notice of termination is provided to the Company, the Customer's billing may require adjustment to reverse any seasonal adjustments applied to charges for consumption after the automatic renewal date.

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge:

Unmetered .... $11.91 per month
Single Phase .... $19.91 per month
Three phase .... $31.91 per month

Demand Charge:
$9.71 per kW of billing demand in the months of December, January, February and March and $7.21 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month in excess of 10 kW.

Energy Charge:
First 3,500 kilowatt-hours .... @ 12.241¢ per kWh
All excess kilowatt-hours .... @ 9.283¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 21.026 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Minimum Monthly Charge:

Unmetered .... $11.91 per month
Single Phase .... $19.91 per month
Three Phase .... $31.91 per month

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $48.89 per month

Demand Charge:
$8.15 per kVA of billing demand in the months of December, January, February and March and $5.65 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 50,000 kilowatt-hours .... @ 10.466¢ per kWh
All excess kilowatt-hours .... @ 8.507¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 21.026 cents per kWh plus the Basic Customer Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $85.20 per month

Demand Charge:
$7.82 per kVA of billing demand in the months of December, January, February and March and $5.32 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 75,000 kilowatt-hours .... @ 10.105¢ per kWh
All excess kilowatt-hours .... @ 8.427¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 21.026 cents per kWh plus the Basic Customer Charge. The Maximum Monthly Charge shall not apply to Customers who avail of the Net Metering Service Option.

Discount:

A discount of 1.5% of the amount of the current month's bill will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #4.1
STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service where the electricity is supplied by the Company and all fixtures, wiring and controls are provided, owned and maintained by the Company.

Monthly Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

	Sentinel/Standard	Post Top
High Pressure Sodium		
100W (8,600 lumens)	$18.10	$19.29
150W (14,400 lumens)	22.60	-
250W (23,200 lumens)	32.23	-
400W (45,000 lumens)	45.27	-
Light Emitting Diode		
LED 100	$15.94	-
LED 150	17.97	-
LED 250	21.77	-
LED 400	25.17	-

Special poles used exclusively for lighting service*

Wood	$6.12
30' Concrete or Metal, direct buried	8.55
45' Concrete or Metal, direct buried	14.15
25' Concrete or Metal, Post Top, direct buried	6.06

Underground Wiring (per run)*

All sizes and types of fixtures	$14.42

* Where a pole or underground wiring run serves two fixtures paid for by different parties, the above rates for such poles and underground wiring may be shared equally between the two parties.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Customers that reduce their demand in aggregate will be treated as a single Customer under this rate option. The aggregated Customer must provide a single point of contact for a request to Curtail.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{(\text{Maximum Demand during Peak Period x 1573 hours})}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced for failure to Curtail in a winter period as follows:

1. For the first 5 curtailment requests the Curtailment Credit will be reduced 25% for each failure to Curtail.

2. After the 5th curtailment 50% of the remaining Curtailment Credit, if any, will become vested ("Vested Curtailment Credit").

3. For all remaining curtailment requests the Curtailment Credit will be reduced by 12.5% for each additional failure to Curtail.

If a Customer fails to Curtail four times during a winter period, then:

1. The Customer shall only be entitled to the Vested Curtailable Credit, if any.

2. The Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Availability:

For Customers who use generation on their Serviced Premises to offset part or all of the electrical energy requirements of the Serviced Premises. Energy generated in excess of the requirements of the Serviced Premises is permitted to be credited against the Customer's energy purchases from the Company in accordance with this rate option.

Net Metering Service is available for any Serviced Premises that is supplied from the Company's distribution system, is billed under one of the Company's metered service rates, and which has generation electrically connected to it that meets the requirements of these provisions. Net Metering Service is not available for un-metered service accounts.

In order to avail of the Net Metering Service Option, Customers must submit a completed Net Metering Service Application to the Company demonstrating the Customer's eligibility for Net Metering Service.

Availability of the Net Metering Service Option will be closed once the provincial aggregate generating capacity for Net Metering Service of 5.0 MW has been met.

Customers that avail of the Net Metering Service Option must maintain compliance with all requirements of this Option. The Company shall have the right to verify compliance through inspection or testing.

Metering:

Net Metering Service will ordinarily be metered using a Company-supplied single meter capable of registering the flow of electrical energy in two directions. The meter will separately capture both the energy supplied to the Customer by the Company and the energy supplied to the Company by the Customer.

At the Company's option, the output of the Customer's generation may be metered separately. In that case, the Customer shall provide the Company with the access necessary to install and maintain the required metering equipment.

The Customer shall pay all costs to upgrade the metering equipment for Net Metering Service if the existing electrical meter at the Serviced Premises is not capable of safely and reliably measuring both the energy supplied to the Customer by the Company and the energy supplied to the Company by the Customer.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Billing:

Each account availing of Net Metering Service will be billed on the rate normally applicable to the Customer's class of Service.

The Customer's net monthly bill will be determined by deducting the Customer Generation Credit from the total of all charges for Service. The Customer Generation Credit equals the Generation Energy Credit, in kilowatt-hours ("kWh") multiplied by the rate applicable to the Customer's class of Service during the billing month.

The "Generation Energy Credit" is the sum of the kWh energy supplied by the Customer to the Company during the billing month plus Banked Energy Credits. The Generation Energy Credit for a billing month shall not exceed the energy supplied by the Company to the Customer during that month.

"Banked Energy Credits" are the amount of kWh energy supplied by the Customer to the Company that exceeds the kWh energy supplied by the Company to the Customer. Banked Energy Credits in excess of those used to calculate the Generation Energy Credit for a billing month will be carried forward to the following month.

The balance of the Customer's Banked Energy Credits carried forward will be settled annually by means of a credit on the Customer's bill for the Annual Review Billing Month. The Annual Review Billing Month will be determined by the Customer, in consultation with the Company, during the process of implementing Net Metering Service. Settlement of Banked Energy Credits will be computed based upon the then-current 2nd block energy charge in Newfoundland and Labrador Hydro's Utility Rate applicable to service provided to the Company.

Whenever a Customer's participation in the Net Metering Service Option is discontinued, any unused Banked Energy Credits will be settled with a credit on the Customer's next bill.

All customers must pay Harmonized Sales Tax (HST) on the energy supplied by the Company to the Customer during the billing month. If a Customer availing of Net Metering Service is required by law to collect HST on the energy they supply to the Company, the Company will pay HST to the Customer based on the amount of the Customer Generation Credit. It is the Customer's responsibility to notify the Company in writing if they are required to collect HST on the energy they supply to the Company.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Special Conditions:

Special conditions in this clause do not supersede, modify or nullify the conditions accompanying the metered rate schedules applicable to the Customer's class of Service.

To avail of Net Metering Service, a single Customer must own and maintain responsibility for the Serviced Premises, the generation and the electrical facilities connecting it to the Company's distribution system.

To qualify for Net Metering Service, the Customer's generation must meet the following requirements:

i) be designed not to exceed the annual energy requirements of the buildings and facilities metered together on the Serviced Premises;
ii) have a manufacturer's nameplate capacity rating totaling not more than 100 kW, except where a lower rating is stipulated by the Company for technical reasons;
iii) be electrically connected through Customer-owned electrical facilities to the Serviced Premises to which Net Metering Service is being provided;
iv) produce electrical energy from a renewable energy source, including wind, solar, photovoltaic, geothermal, tidal, wave, biomass energy or other renewable energy sources that may be approved by the Company on a case-by-case basis; and
v) meet all applicable safety and performance standards established by the Canadian Electrical Code, the Public Safety Act and the Company's Interconnection Requirements.

All Customer-owned wiring, equipment and devices associated with generation utilized for Net Metering Service shall conform to the Company's interconnection requirements.

The Customer will retain the rights to any renewable energy credits or greenhouse gas-related credits arising from the use of renewable energy sources to generate electricity in accordance with this Option.

A Customer availing of Net Metering Service is responsible for all costs associated with their own facilities. The Customer shall also be required to pay all costs incurred by the Company to modify the utility supply for the provision of Net Metering Service, and for necessary engineering or technical studies required in connection with the provision of Net Metering Service to the Customer.

The approval of an application for Net Metering Service will be subject to the applicant entering into a Net Metering Interconnection Agreement with the Company.

If an applicant approved for Net Metering Service does not proceed with operation of its generation in accordance with its approval within two years from the date of the Company's approval of the application, the approval will be rescinded.

NEWFOUNDLAND POWER INC.
NET METERING SERVICE OPTION
(for Rates #1.1, #1.1S, #2.1,#2.3, and #2.4 only)

Approval of Net Metering Service may be revoked if a Customer is found to be in violation of provisions of the Company's Rules and Regulations.

If participation in the Net Metering Service Option is discontinued, the Customer must re-apply to the Company to avail of the Net Metering Service Option.

NEWFOUNDLAND POWER INC.
PENSION CAPITALIZATION COST DEFERRAL ACCOUNT

Pension Capitalization Cost Deferral Account

This account shall be charged with amounts equal to cost impacts resulting from the change in capitalizing pension costs from the indirect method via general expenses capitalized to the direct method via a labour loader, effective January 1, 2023.

Charges to the account will be amortized over a 5-year period commencing January 1, 2023.

Transfers to, and from, the account will be tax-effected.

NEWFOUNDLAND POWER INC.
LOAD RESEARCH AND RATE DESIGN COST DEFERRAL ACCOUNT

Load Research and Rate Design Cost Deferral Account

This account shall be charged with the costs incurred in conducting a Load Research Study and a Retail Rate Design Review (collectively, the "Studies").

These costs include: the development of a detailed framework for each of the Studies in 2022; and costs to conduct each of the Studies in accordance with the framework.

Transfers to, and from, the proposed account will be tax-effected.

The disposition of any balance in this account will be subject to a future order of the Board.

NEWFOUNDLAND POWER INC.
ELECTRIFICATION COST DEFERRAL ACCOUNT

Electrification Cost Deferral Account

This account shall be charged with the costs incurred in implementing the Customer Electrification Program Portfolio in accordance with Board orders and approved electric vehicle charging infrastructure capital costs until otherwise ordered by the Board.

Electrification program costs include: detailed program development, promotional materials, advertising, pre and post customer installation checks, incentives, processing applications and incentives, training of employees and trade allies, program evaluation costs and the costs to operate Company-owned charging stations.

This account shall also be charged the costs of major studies such as pilot programs, comprehensive customer surveys and potential studies that cost greater than $100,000.

This account shall be credited with the receipt of government funding related to electrification programs and electric vehicle charging infrastructure as well as any revenues associated with the operation of Company-owned charging stations.

The account shall exclude electrification expenditures that are general in nature and not associated with a specific electrification program, such as costs associated with providing electrification awareness, and general planning, research and supervision costs.

The account shall be increased (reduced) by an interest charge (credit) on the balance in the account at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base. The account will not be included in the Company’s calculation of rate base until otherwise ordered by the Board.

Transfers to, and from, the proposed account will be tax-effected.

This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred.

Recovery of annual amortizations of costs in this account shall be through the Company’s Rate Stabilization Clause or as otherwise ordered by the Board.

Newfoundland & Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
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DECISION **2023 NSUARB 12**
M10431

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF A GENERAL RATE APPLICATION by NOVA SCOTIA POWER INCORPORATED for approval of certain revisions to its Rates, Charges and Regulations

BEFORE:	Stephen T. McGrath, LL.B., Chair Roland A. Deveau, K.C., Vice Chair Steven M. Murphy, MBA, P.Eng., Member
APPLICANT:	**NOVA SCOTIA POWER INC.** Colin J. Clarke, K.C. Blake Williams, Counsel
INTERVENORS:	**SEE APPENDIX A** **CONSUMER ADVOCATE** William J. Mahody, K.C. Christine Murray, Counsel **SMALL BUSINESS ADVOCATE** E.A. Nelson Blackburn, K.C. Melissa P. MacAdam, Counsel **INDUSTRIAL GROUP** Nancy G. Rubin, K.C. Dylan MacDonald, Counsel **AFFORDABLE ENERGY COALITION** Peter Duke, Counsel **DALHOUSIE UNIVERSITY** Nancy G. Rubin, K.C. **ECOLOGY ACTION CENTRE** Jacob Thompson

BRAGG COMMUNICATIONS INCORPORATED (EASTLINK)
Robert G. Grant, K.C.

EFFICIENCY ONE
James R. Gogan, Counsel
David Irvine, Counsel

FREEMAN LUMBER
Noah Entwisle, Counsel

EASTWARD ENERGY LIMITED
Michael Johnston
Kristen Wilcott

MAINLAND TELECOM INC.
Burt McCaffrey

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA
James MacDuff, Counsel
Melanie Gillis, Counsel

NCS MANAGED SERVICES
Emerich R. Winkler Jr.

NOVA SCOTIA DEPARTMENT OF NATURAL RESOURCES AND RENEWABLES
Daniel Boyle, Counsel

NOVA SCOTIA LIBERAL CAUCUS
Zach Churchill, Leader

NOVA SCOTIA NDP CAUCAUS
Claudia Chender, Leader

PORT HAWKESBURY PAPER LP
James McDuff, Counsel
Melanie Gillis, Counsel

ROGERS COMMUNICATIONS CANADA INC.
Leslie J. Milton, Counsel

XPLORE INC. (formerly Xplornet Communications Inc.)
Carl MacQuarrie, Counsel

BOARD COUNSEL: S. Bruce Outhouse, K.C.

HEARING DATES: September 12-23, 2022

UNDERTAKINGS: October 14, 2022

FINAL SUBMISSIONS: December 21, 2022

DECISION DATE: **February 2, 2023**

DECISION: **The Board approves most of the GRA Settlement Agreement providing for average rate increases of 6.9% across all customer classes in each of 2023 and 2024. The Board approves the rates and charges for 2023 effective the date of this decision and the rates and charges for 2024 effective January 1, 2024. The Board also approves the Storm Rider, the DSM Rider and the Decarbonization Deferral Account in principle, each as described in the GRA Settlement Agreement. The Board does not approve three items in the agreement, namely the proposed AMI Opt-out fee, the creation of a regulatory asset for Annapolis Tidal Generating Facility, and the four Maritime Link transmission capital projects.**

The Board endorses an agreement between the Affordable Energy Coalition, the Consumer Advocate, and NS Power to consider possible changes to the bill payment, credit and collection rules for low-income customers.

The Board directs NS Power to conduct a depreciation study and to start a consultative process to develop a Climate Change Adaptation Plan.

The Board denies a request by the Municipal Electric Utilities for a BUTU Tariff GHG credit, but accepts a recommended change in determining a charge for Capacity Based Ancillary Services and directs a review of other charges.

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1.0 SUMMARY

[1] NS Power applied to the Nova Scotia Utility and Review Board for smoothed power rate increases of 3.3% per year for residential customers effective August 1, 2022, January 1, 2023, and January 1, 2024. Proposed rate increases for other customer classes varied from this amount, with the proposed overall average smoothed rate increases amounting to 3.6%.

[2] This was NS Power's first general rate application (GRA) for an increase to its non-fuel rates since the Board's decision setting 2013-2014 rates.

[3] NS Power's original forecast for fuel and purchased power costs for the application was generated in May 2021. NS Power filed a Fuel Update on September 2, 2022. It showed a significantly higher forecast for fuel and purchased power costs, representing an increase of $681.5 million over the original forecast for the period from 2022 to the end of 2024. The Province of Nova Scotia agreed to provide some relief to NS Power customers from this amount by exempting NS Power from approximately $165 million of greenhouse gas (GHG) compliance expenses to the end of 2022.

[4] The Board held the public hearing from September 12 to 23, 2022. The evidentiary record contained over 30,000 pages of information filed by NS Power and the parties, including representatives for the major customer classes representing most of the Utility's customers.

[5] On October 19, 2022, the Nova Scotia Government introduced Bill 212 in the Legislature, after the hearing had finished, but before written Closing Submissions by the parties. The legislation came into effect on November 8, 2022. It amended the *Public Utilities Act*, adding new provisions that specifically impacted the current GRA, including, among other items, a requirement that the net rate increase for the Utility, across all rate

classes, in 2022, 2023 and 2024 must not be greater than 1.8%, with the exception of an increase for fuel costs and demand side management costs. Further, the legislation required revenue generated from the net rate increase may only be used to improve service reliability.

[6] On November 24, 2022, NS Power filed a GRA Settlement Agreement with the Board, resolving many of the issues in the GRA. The GRA Settlement Agreement was signed by representatives for all major customer classes, representing most of NS Power's customers. In addition to agreeing on many issues canvassed in the GRA, the parties agreed that, with the Board's approval, the average rate increase across all customer classes should be 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024. The parties also agreed to defer part of the expected increase in fuel costs to later years.

[7] The Board is keenly aware that electricity rates are already challenging for many customers and any rate increase will be difficult, especially for those with low or fixed incomes. However, the Board does not have the authority to provide special rates for these customers and, as noted by the Nova Scotia Court of Appeal, the Board's regulatory power under the *Public Utilities Act* is not an instrument of social policy.

[8] Further, consistent with principles of utility rate regulation recognized by the Supreme Court of Canada, the Board cannot simply disallow NS Power's reasonable costs to make rates more affordable. These principles ensure fair rates and the financial health of a utility so it can continue to invest in the system providing services to its customers. While the Board can (and has) disallowed costs found to be imprudent or unreasonable, absent such a finding, NS Power's costs must be reflected in the rates

paid by customers. Regulatory tools, such as deferrals, are available to the Board to mitigate the impact of rate increases, but there are trade-offs involved with using these tools as they often result in higher costs in the longer term.

[9] Having reviewed all the evidence, submissions and the law, the Board is satisfied that the GRA Settlement Agreement, considered as a whole, is in the public interest and that it should be approved, with certain exceptions. The Board is satisfied that the negotiated average 6.9% rate increases in each of 2023 and 2024 are reasonable and appropriate, and that the increases comply with recent amendments to the *Public Utilities Act* introduced through Bill 212. The Board approves the rates and charges for 2023 effective the date of this decision and the rates and charges for 2024 effective January 1, 2024.

[10] In considering issues like the rate of return and the financing costs for fuel and other deferrals, the Board finds that NS Power's recent credit downgrades are a relevant factor because they heighten concerns around NS Power's credit metrics and the risk of further downgrades, resulting in the potential imposition of even more costs on ratepayers.

[11] In the GRA Settlement Agreement, a balance was struck between NS Power and representatives of most of its customer classes (including the Consumer Advocate on behalf of all residential customers and the Affordable Energy Coalition, which works on behalf of low- and modest-income Nova Scotians across the province). Given the broad acceptance by customer representatives and other parties, and the looming cost pressures likely to arise from higher forecasted fuel costs and the transition to a net-zero carbon economy, the Board finds the proposed rate increases in the GRA

Settlement Agreement to be just. It is not appropriate in this case to defer even more fuel costs for additional and temporary rate relief in the test years. This would run the very real risk of compounding rate pressures in the future and reducing the flexibility that may be available to manage those costs in a reasonable timeframe.

[12] The Board also finds that other components of the GRA Settlement Agreement appropriately resolve issues raised in the application. As a result, the Board approves the following:

- Maintaining NS Power's current return on equity of 9.0%, with an earnings band of 8.75% to 9.25%. The equity thickness for rate setting purposes increases from 37.5% to 40.0%;
- Agreeing in principle to the establishment of a Decarbonization Deferral Account to address the retirement of coal plants and related decommissioning costs, subject to a further consultative process;
- Implementing a Storm Cost Recovery Rider for a three-year trial period, and a DSM Cost Recovery Rider;
- Conducting an updated Cost of Service Study and Line Loss Study before the next GRA or by December 31, 2025, whichever is sooner, subject to stakeholder engagement;
- Applying a 25% reduction to the proposed increase to the 2023 customer charges;
- Increasing the credit amount in the Large Industrial Interruptible Rider;
- Adopting the negotiated amount for the pole attachment fee as per the agreement between NS Power and the telecommunications carriers; and
- Capping the Open Access Transmission Tariff at a maximum increase of 1.8% in 2023 and 0% in 2024.

[13] The Board does not approve three items in the GRA Settlement Agreement. It does not approve NS Power's proposed AMI opt-out fee. It does not approve the regulatory amortization of the Annapolis Tidal Generation Facility, which is to remain in rate base. Further, the Board defers approval of the four Maritime Link transmission

capital projects originally totalling about $45 million until benefits to ratepayers have been demonstrated, as discussed later in this decision.

[14] Moreover, the Board directs NS Power to prepare a depreciation study before the next GRA. The Board also endorses an agreement between the Affordable Energy Coalition, the Consumer Advocate and NS Power to review the outcomes of 2013 changes to the Utility's bill payment, credit and collection rules for low-income customers and to consider additional changes. In addition, the Board directs NS Power to engage in a consultative process to develop a Climate Change Adaptation Plan.

[15] The Board denies the Municipal Electric Utilities' request for a Wholesale Market Backup/Top-up (BUTU) Tariff GHG credit. However, the Board accepts one of their recommendations for Capacity Based Ancillary Services, and directs a review of their other recommendations.

[16] Nova Scotia is on the brink of unprecedented change in the energy sector. The Company and its customers must contend with this change at an accelerating pace. Government, regulators, and utilities will need to work collaboratively to mitigate the risks of this rapid change, and to ensure they meet the aggressive decarbonization goals set by federal and provincial governments. In terms of the comprehensive GRA Settlement Agreement that was signed, and the agreement to pursue consultative processes on the Decarbonization Deferral Account and an updated Cost of Service Study, the Board considers it a positive development that there is a constructive dialogue occurring between the Utility and its customers about the energy transition.

2.0 BACKGROUND

[17] This decision is about an application filed on January 27, 2022, by Nova Scotia Power Incorporated (NS Power, Company, Utility), for approval of revisions to its Rates, Charges and Regulations (application or GRA). This was NS Power's first general rate application for an increase to its non-fuel rates since the Board's decision setting 2013-2014 rates. Since that proceeding, inflation has increased over 20% from 2014 to 2022.

[18] NS Power filed an updated application on February 18, 2022, to address an issue with income tax and interest related to the Fuel Adjustment Mechanism (FAM) balance. The updated filing also reflected NS Power's withdrawal of their request for a system access charge for customer solar panels.

[19] The application requested the Board's approval of a Rate Stability Plan (RSP). The proposed RSP was a three-year rate plan, with smoothed overall rate increases for each of the customer classes as outlined in this excerpt from Figure 12-5:

	August 1, 2022	January 1, 2023	January 1, 2024
Domestic Service Tariff			
Total	**3.3%**	**3.3%**	**3.2%**
Small General Tariff			
Total	**3.6%**	**3.7%**	**3.7%**
General Tariff			
Total	**4.0%**	**4.0%**	**4.0%**
Large General Tariff			
Total	**5.2%**	**5.2%**	**5.2%**
Small Industrial Tariff			
Total	**5.1%**	**5.2%**	**5.3%**
Medium Industrial Tariff			
Total	**5.6%**	**5.6%**	**5.7%**
Large Industrial Tariff			
Total	**3.3%**	**3.4%**	**3.5%**
Other Classes			
Total	**0.0%**	**0.2%**	**0.3%**
Total FAM Classes			
Total	**3.6%**	**3.6%**	**3.6%**

[Exhibit N-16, Figure 12-5, pp. 107-108]

[20] NS Power's application also included:

- A request to maintain its return on common equity of 9.0%, but to increase the approved range of earnings from 8.50% to 9.50% (currently 8.75% to 9.25%), and to phase-in an increase to the common equity component from 37.5% towards 45%;
- A proposal for a 50/50 Earnings Sharing Mechanism for overearnings, with the ratepayers' share applied to the Decarbonization Deferral Account (DDA);
- A Storm Rider to recover costs related to Level 3 and 4 storms;
- A Decarbonization Deferral Account;
- A Demand Side Management Rider (DSM Rider or DCRR);
- Changes to the Miscellaneous Charges in NS Power's Regulations, including:
    i. The establishment of an Advanced Metering Infrastructure (AMI) Opt-out Fee, including revisions to Regulation 5.1 (Meter Reading);
    ii. Changes to the fees and charges in Regulations 7.1, 7.2 and 7.3 as more fully described in the application; and
    iii. Increase to the Pole Attachment Fee from $14.15 to $37.71;
- Changes to the Domestic Service and Small General Customer Charges;
- An increase to the Large Industrial Interruptible Credit;
- Changes to rates in the Open Access Transmission Tariff (OATT); and
- Approval of four Capital Work Orders originally totalling $44.7 million for Maritime Link related transmission work.

[21] The proposed rate increases included increased fuel costs. Any Fuel Adjustment Mechanism Actual Adjustments (AA) or Balancing Adjustments (BA) calculated during the Rate Stability Period would be deferred to 2025.

[22] NS Power asked to delay its Fuel Update and the start of the hearing to facilitate discussions with the Province of Nova Scotia about the significant escalation in fuel and purchased power costs since NS Power's forecast for the general rate application. NS Power and the Province were discussing whether measures could be taken to lessen the impact on customers. NS Power's request was supported by the Province, through the Department of Natural Resources and Renewables (NRR). The Board granted these requests.

[23] NS Power's original forecast for fuel and purchased power costs for the general rate application was generated in May 2021. NS Power filed a Fuel Update on

September 2, 2022, which showed that total forecast fuel and purchased power costs for the test period were projected to increase by $681.5 million more than initially forecast in its application (approximately one-third of its original forecast fuel budget). The Fuel Update had a potentially significant impact on NS Power's proposed power rates for its customers. However, the Province of Nova Scotia agreed to provide relief to NS Power customers for the GHG compliance expenses to the end of 2022, which the Company previously forecast as part of its fuel costs. This GHG relief is forecast to remove GHG compliance costs to the end of 2022 of about $165 million from NS Power's Fuel Update forecast. Assuming NS Power is subject to the Federal Backstop Program for GHG compliance, which is scheduled to begin on July 1, 2023, the Company estimates the additional cost for emissions compliance in 2023 and 2024 will be $116 million and $127 million, respectively. These latter two amounts for the cost of emissions compliance were not included in the updated fuel forecast provided by NS Power.

[24] The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380 (*Act* or *PUA*).

[25] A number of formal Intervenors responded to NS Power's application and participated in the hearing. The Consumer Advocate (CA); Small Business Advocate (SBA); the Industrial Group (IG); Dalhousie University; the Affordable Energy Coalition; the Ecology Action Centre; Municipal Electrical Utilities of Nova Scotia (MEUs); Port Hawkesbury Paper LP (PHP); Nova Scotia Department of Natural Resources and Renewables (NRR); EfficiencyOne (EOne); Bragg Communications Incorporated, operating as Eastlink (Eastlink); the Nova Scotia Liberal Caucus Office; the Nova Scotia NDP Caucus Office; and Freeman Lumber, participated in the hearing. Albert Dominie,

the consultant for the Municipal Electric Utilities, passed on the eve of the hearing. In his current role, and in his former capacity as NS Power's Manager of Rates and Regulations, Mr. Dominie contributed in a significant way to electricity proceedings before the Board. His knowledge and insight will be missed.

[26] The Notice of Public Hearing advised the public that they could file submissions with the Board outlining their views regarding NS Power's application. The Board received nearly 1,000 letters of comment from the public and two individuals made presentations at the evening session on September 12, 2022.

[27] Many of the written comments noted the impact the rate increases would have on customers, especially on low- and fixed-income customers. A number of other concerns were noted, including: the proposed system access charge on solar panel installations; executive compensation and bonus levels; rate of return and company earnings; the reliability of the electricity system; the need for renewable energy; and the phasing-out of coal plants.

[28] These concerns were echoed during the evening session, along with additional concerns about the cost of living and the need to avoid the proposed rate increases. During this session, it was also suggested that there is no financial incentive for NS Power to abandon its large capital-intensive coal-fired infrastructure and transition to renewable sources of energy, including distributed energy resources, adding that such renewable sources are generally more affordable. Further, one speaker noted that NS Power earns return on any deferred fuel costs, and that alternative financing should be pursued from governments and banks for such deferrals. For similar reasons, the same speaker suggested that the DDA should be rejected.

[29] The Board considered all the comments made in the written submissions and during the evening session in making its decision. The Board is mindful of its responsibility to consider the public interest in its decisions.

[30] On November 24, 2022, following the hearing, but before written submissions were completed, NS Power filed a Settlement Agreement between itself and Intervenors representing most of NS Power's customers which resolved many of the issues in this proceeding. The parties agreed that the average rate increase across all customer classes would be 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024. Also, during the hearing, NS Power filed a Settlement Agreement with the telecommunications carriers who had intervened in the proceeding about the proposed increase to the Pole Attachment Fee.

3.0 BOARD'S AUTHORITY UNDER THE *PUBLIC UTILITIES ACT*

[31] The Board is an administrative body, established under the laws of the Province of Nova Scotia as a continuation of predecessor boards under the *Utility and Review Board Act*, S.N.S. 1992, c. 11 (*UARB Act*). It exercises adjudicative and regulatory decision-making authority under approximately 40 statutes and related regulations. In doing so, it must follow legislative requirements and administrative law principles. The Board's decisions may be appealed to the Nova Scotia Court of Appeal on any question of law or its jurisdiction.

[32] The Board is what has sometimes been referred to as a "creature of statute." In *Administrative Law in Canada*, 7th ed. (LexisNexis Canada, 2022), Sara Blake described the powers of such entities:

> An administrative tribunal is created by statute and has only those powers conferred on it by statute. It has no inherent power to undertake proceedings or to make an order that affects a person's substantive rights or obligations. Most Interpretation Acts confer on tribunals all powers that are necessary to enable them to make the decisions and do the things they are expressly empowered to do. The powers that exist by necessary implication may be deduced from the wording of the Act, its structure, and its purpose. A tribunal's powers should be interpreted so as to enable the tribunal to fulfil the purposes of the statute rather than sterilized by overly technical interpretation, but statutory powers may not be expanded to accomplish what the tribunal thinks it ought to do to further its mandate in the public interest. If a tribunal has broad authority to make any order to remedy a violation of the Act, the remedy must be related to the violation, its consequences and the purposes of the Act.
>
> [p. 137]

[33] The Board summarized the application of these principles to itself in *Re Nova Scotia Power Incorporated* [2018 NSUARB 45]:

> [47] The UARB is a creature of statute and can only obtain jurisdiction from two sources: one, express grant of jurisdiction under the *PUA* and under other statutes (express powers); and two, from common law by application of the doctrine of jurisdiction by necessary implication (implicit powers).
>
> [48] In *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board)*, [2006] SCC 4, the majority decision stated, at paragraph 51, that:
>
>> …the powers conferred by an enabling statute are construed to include not only those expressly granted but also, by implication, all powers which are practically necessary for the accomplishment of the object intended to be secured by the statutory regime created by the legislature.
>
> [49] The majority also held, at paragraph 74 of the *ATCO Gas* decision, that:
>
>> …the doctrine of jurisdiction by necessary implication will be of less help in the case of broadly drawn powers than for narrowly drawn ones. Broadly drawn powers will necessarily be limited to only what is rationally related to the purpose of the regulatory framework.

[34] The Board's general functions, power, duties and jurisdiction are expressly addressed in the *UARB Act*:

> **Functions, powers and duties**
>
> 4 (1) The Board has those functions, powers and duties that are, from time to time, conferred or imposed on it by

(a) this Act, the *Assessment Act*, the *Expropriation Act*, the *Gasoline and Diesel Oil Tax Act*, the *Health Services Tax Act*, the *Heritage Property Act*, the *Insurance Act*, the *Motor Carrier Act*, the *Municipal Government Act*, the *Public Utilities Act*, the *Education Act*, the *Shopping Centre Development Act*, the *Tobacco Tax Act* or any enactment; and

(b) the Governor in Council.

(2) The Governor in Council may assign to the Board the powers, functions and duties of any board, commission or agency and while the assignment is in effect, that board, commission or agency is discontinued and Sections 49 and 50 apply *mutatis mutandis* with respect to that board, commission or agency.

Jurisdiction

22 (1) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it.

(2) The Board, as to all matters within its jurisdiction pursuant to this Act, may hear and determine all questions of law and of fact.

[35] The *PUA* gives the Board broad regulatory oversight over public utilities and the authority to discharge its regulatory responsibilities. The Board's principal responsibility in regulating utilities is to help ensure:

a) safe and adequate service;

b) just and reasonable rates; and

c) lowest long-term cost.

[36] Public utilities tend to be natural monopolies. As such, the impact of competitive forces on those entities may be muted or non-existent. In the absence of these forces, the Board's ratemaking function is designed to allow the utility to recover its legitimate costs of providing service and an opportunity to earn a reasonable profit at rates that are fair for its customers. This ratemaking function has been described by the Nova Scotia Court of Appeal as a surrogate for competition and not a tool for implementing social policy:

32 The Board sets rates for a utility that has a virtual monopoly on the supply of electric power. The Board's decision discusses this process: (2005 NSUARB 27)

> [17] … NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of-service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the utility is permitted, under the ***Act***, to recover the reasonable and prudent costs of providing the service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.
>
> [18] It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.
>
> [19] In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly.

33 I agree with this portrayal of the background to the Board's rate-making function. The Board's regulatory power is a proxy for competition, not an instrument of social policy. [Emphasis added]

[*Dalhousie Legal Aid Service v. Nova Scotia Power Inc.*, 2006 NSCA 74]

[37] As noted already, the Board's powers are defined by legislation. Section 45 of the *PUA* requires the Board to use a cost of service methodology to set rates and entitles the utility to a just and reasonable return:

Amount utility entitled to earn annually

45(1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly.

45(2) Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. [Emphasis added]

[38] In legislation, the word “shall” is mandatory. However, the phrases “just and reasonable” and “reasonable and prudent” allow the Board to exercise some discretion. Additionally, the Board’s mandate under the *PUA* encompasses a significant public interest component (*Nova Scotia (Attorney General) v. Nova Scotia (Utility and Review Board*), 2019 NSCA 66, paras. 113-116). But as considered above, the Board’s implicit powers are tied, by necessary implication, to the purposes of the statute.

[39] The Nova Scotia Supreme Court, Appeal Division decision in *Nova Scotia (Public Utilities Board) v. Nova Scotia Power Corporation*, (1976) 18 N.S.R. (2d) 692 (the *Contracts Case*) is often referenced for its consideration of the scheme of regulation under the *PUA*:

> 17 <u>The scheme of regulation established by the Act envisages and indeed compels control by the Board of all aspects of a utility's operation in providing a controlled service. Two great objects are enshrined - that all rates charged must be just, reasonable and sufficient and not discriminatory or preferential, and that the service must be adequately, efficiently and reasonably supplied to the public. Almost all provisions of the Act are directed toward securing these two objects - that a public utility give adequate service and charge only reasonable and just rates.</u>
>
> 18 The service requirement is expressed in s. 48, as follows:
>
>> 48 Every public utility is required to furnish service and facilities reasonably safe and adequate and in all respects just and reasonable.
>
> 19 This general requirement is supplemented by provisions such as s. 25 respecting pole line standards, s. 52 prohibiting electric voltage and frequency variations of more than 4% and ss. 49-51 respecting abandonment or duplication of service, and by rules and regulations made by the Board for each utility's operation. Compliance with this requirement is accomplished by the Board's continuing supervision of a utility (s. 19), by requiring a utility to submit to the Board detailed reports and accounts, "to show completely and in detail the entire operation of the public utility in furnishing its product or service to the public" (s. 33; also ss. 26, 45-47). The Board may investigate the adequacy of service on its own motion (s. 18) or on complaint (s. 78(1)), and by its staff may inspect books of a utility (s. 75) and make tests or examinations to determine the safety and adequacy of service (s. 77).
>
> 20 Rates must be "just" (s. 41) and must not be "unreasonable or unjustly discriminatory" (s. 18 and s. 78(1)), or "unjust, unreasonable, insufficient or unjustly discriminatory, or . . . preferential" (s. 82(1)). The "justness" of rates has two aspects - rates of a utility as a whole must be "reasonable" and just for the public it serves and just and "sufficient" for the utility itself - and the rates for the various customers or classes of customer of a utility must not as between each other be "unjustly discriminatory" or "preferential".

21 The control of the over-all level of rates has its keystone in s. 42(1) which states:

> 42 (1) Every public utility shall be entitled to earn annually such return as the Board deems just and reasonable on the rate base as fixed and determined by the Board . . .

…

23 <u>The concept of a utility securing a reasonable return on its rate base automatically makes specific the apparently vague standard that rates be "just". The utility's economic health and its ability to supply adequate service and to finance capital expansion are assured by giving it a "just and reasonable" return. Overall rates must thus be sufficient to produce that return after allowing operating expenses and other "just allowances" (s. 42(2)). The rates must thus be "sufficient" to produce that return, no less and no more.</u>

24 The public interest charges the Board with the duty of ensuring no extravagance by a utility in either capital or operating expenditure. The rate base is to include only assets "used and useful" in providing service (s. 29 (1)). Additions to it are controlled by the requirement that Board approval be secured for any new construction project of more than $5,000 (s. 34 as amended). The expenses for rate-making purposes are only those the Board allows "as reasonable and prudent and properly chargeable to operating account" (s. 42(2)). Other "just allowances" are prescribed by the Act and Regulations, *e.g.* annual depreciation charges (ss. 35-38).

…

26 The Board has on occasion summarized its duty in terms which, accurately I believe, emphasize the comprehensive nature of its control of the rates and services of a utility. Its decision of February 25, 1970, in respect of an application of Maritime Telegraph and Telephone Company Limited, contains the following at p. 25 of the Board's Report for 1970:

> A public utility is obligated to provide services that are reasonably safe and adequate and is entitled to compensation therefor by the charging of rates that are not unjustly discriminatory and will provide the public utility with sufficient revenue to enable it to pay its operating expenses including depreciation and income taxes, and have net earnings sufficient to enable it to obtain and service normal and needed capital requirements. It is expected to meet reasonable demands for additional services and to conduct its affairs with efficiency. When an application is made to this Board for approval of revisions in rates, tolls and charges designed to produce additional revenue the public utility is required to produce evidence showing the needs and purposes for which such additional revenue is required. And upon any such application the Board inquires into and examines the adequacy and reasonableness of existing services, the efficiency of the public utility, the nature and extent of the needs and purposes upon which the application is grounded and the propriety of the proposed rate changes.

27 The "propriety" of the rates involves not only the propriety of their over-all level as adjudged by rate base return, but also their propriety for the various classes of customer. The Board's twofold duty is to ensure that the rates as a whole are reasonable and that they are reasonable to all customers *inter se*. This latter aspect of its duty is imposed by the various provisions prohibiting unjust discrimination and requiring equal rates in substantially similar circumstances. [Emphasis added]

[40] In exercising its ratemaking function, following the statutory requirements and mindful of the purposes of the legislation, the Board is also guided by the following long-established, fundamental ratemaking principles, which it noted in its decision for NS Power's rate application in 2002 and a number of rate applications since:

> [21] In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> [22] A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
> 2. Freedom from controversies as to proper interpretation.
> 3. Effectiveness in yielding total revenue requirements under the fair-return standard.
> 4. Revenue stability from year to year.
> 5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
> 6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
> 7. Avoidance of "undue discrimination" in rate relationships.
> 8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
>   (a) in the control of the total amounts of service supplied by the company;
>   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).
>   (Exhibit N-92) (James Bonbright, **Principles of Public Utility Rates**, Columbia University Press, 1961, p. 291)
>
> [23] These principles are well established and form the background against which the current application must be assessed.
>
> [2002 NSUARB 59, paras. 21-23]

[41] The Board continues to make its decisions in accordance with the *PUA* and the principles noted above.

4.0 AMENDMENTS TO THE *PUBLIC UTILITIES ACT* (OCTOBER 2022)

[42] This GRA proceeding was significantly impacted by Bill 212, which the Nova Scotia Government introduced in the Legislature on October 19, 2022, after the hearing had finished, but before written Closing Submissions by the parties. The legislation contained various amendments to the *PUA*, including several new provisions that specifically referenced the current Matter M10431. The amended Bill passed Third Reading on November 8, 2022, and received Royal Assent on November 9, 2022 (S.N.S. 2022, c. 52) (*PUA* amendments or Bill 212). The provisions directly impacting this matter are as follows:

> **64A(3)** For the purpose of Board Case Number M10431, the net rate increase for the utility, across all rate classes, in 2022, 2023 and 2024 must not be greater than one and eight-tenths per cent, with the exception of an increase respecting
>
> (a) fuel and purchased power; and
>
> (b) demand-side management approved by the Board.
>
> **(3A)** Revenue generated from the net rate increase referred to in subsection (3), with the exception of increases respecting a matter referred to in clause (3)(a) or (b),
>
> (a) must be kept separate from other funds of the utility; and
>
> (b) may only be used to improve the reliability of service to ratepayers.
>
> **64AA** For the purpose of Board Case Number M10431,
>
> (a) Nova Scotia Power Incorporated's return on equity must be set at a rate not greater than nine and one-quarter per cent;
>
> (b) Nova Scotia Power Incorporated's equity ratio must not be greater than forty per cent.
>
> **64AB (1)** The Board may approve the payment of interest to Nova Scotia Power Incorporated on an outstanding balance for the Fuel Adjustment Mechanism, or any other regulatory deferral.
>
> **(2)** To be eligible for a payment of interest under subsection (1),
>
> (a) Nova Scotia Power Incorporated must demonstrate a balance is outstanding, or there is a clear demonstrated prediction for an outstanding balance, for a period of not less than twelve months prior to a request for the payment of interest; and

(b) the minimum amount on an outstanding balance must be greater than one million dollars.

(3) Interest must be calculated

(a) from the date the balance is outstanding using simple interest at the Bank of Canada policy interest rate plus one and three-quarters per cent, unless otherwise directed by the Board; and

(b) on a per year basis.

(4) Any request for the payment of interest on an outstanding balance must include the interest calculations for the Board for review.

64C Where Nova Scotia Power Incorporated's regulated return on equity exceeds the range approved by the Board in a calendar year, any amount that exceeds that range must be returned to ratepayers in a manner approved by the Board.

[43] The former version of s. 64A(3) was repealed. While NS Power is unable to be granted a general rate increase within two years of the prior increase (s. 64A(2)), the former s. 64A(3) allowed the Utility to seek a general rate increase sooner, provided the Board found that “exceptional circumstances exist that have caused or will cause substantial financial harm to the ratepayers of the utility or to the utility”. The repeal of the provision removed that exemption.

[44] Further, while not directly impacting the current GRA, the amendments also added the following provision, which will impact NS Power over the longer term leading to the next general rate application:

30(5) The Board shall, with the assistance of such engineers, accountants, valuators, counsel and others as it deems wise or advisable to employ,

(a) inquire into and determine the extent, condition and value of the whole or any portion of the property and assets of Nova Scotia Power Incorporated used and useful in furnishing, rendering or supplying a particular service to or for the public, no later than March 31, 2024; and

(b) set different levels of return on equity for different classes of capital assets of Nova Scotia Power Incorporated to ensure that investment incentives are aligned with ratepayer objectives as submitted to the Board in a hearing for a rate change.

[45] To allow NS Power and the Intervenors to consider the ramifications of the new statutory amendments, the initial Closing Submissions were delayed from the previously scheduled date of November 4, 2022, to November 23, 2022, with Reply Submissions delayed from the prior date of November 18, 2022, to December 21, 2022.

[46] An immediate impact of Bill 212 was that credit rating agencies revised their outlooks for NS Power and Emera. S&P Global and DBRS Morningstar lowered NS Power's credit rating on November 21, 2022, and December 20, 2022, respectively, directly impacting NS Power's financing abilities in the debt markets, putting pressure on its cash flow-to-debt metrics, and potentially discouraging equity investment.

5.0 STATUTORY INTERPRETATION PRINCIPLES

[47] The principles of statutory interpretation apply in determining the intent of any particular statute, including in the Board's interpretation of the statutory provisions in the *Public Utilities Act*, and other legislation relevant to this matter, to determine the scope of the powers conferred upon the Board.

[48] *Verdun v. Toronto Dominion Bank,* [1996] 3 S.C.R. 550, and cases following it (see, for example, *Chartier v. Chartier,* [1998] S.C.J. No. 79; *Re Rizzo & Rizzo Shoes Ltd.*, [1998] 1 S.C.R. 27), make it clear that the Supreme Court of Canada has adopted what it calls the "modern contextual approach" to legislative interpretation, supplanting earlier rules it has supported, such as the "equitable construction approach", the "plain meaning rule", and the "golden rule".

[49] In *Re Rizzo & Rizzo Shoes Ltd.*, Mr. Justice Iacobucci said at paragraph 21:

> ... Elmer Driedger in *Construction of Statutes* (2nd ed. 1983) best encapsulates the approach upon which I prefer to rely. He recognizes that statutory interpretation cannot be founded on the wording of the legislation alone. At p.87, he states:

> Today there is only one principle or approach, namely, the words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament.

[50] On the matter of the purpose of legislation, *Nova Scotia (Crop and Livestock Insurance Commission) v. DeWitt,* [1996] N.S.J. No. 566 (S.C.), is of interest. Goodfellow, J., quotes Driedger (3rd ed.) at pages 38-39:

> ... Modern courts do not need an excuse to consider the purpose of legislation. Today purposive analysis is a regular part of interpretation, to be relied on in every case, not just those in which there is ambiguity or absurdity. As Matthews, J.A. recently wrote in *R. v. Moore* [(1985), 67 N.S.R. (2d) 241, at 244 (C.A.)]:
>
> > From a study of the relevant case law up to date, the words of an Act are always to be read in light of the object of that Act. Consideration must be given to both the spirit and the letter of the legislation.
>
> ... *Thomson v. Canada* (Minister of Agriculture) (1992), 1 S.C.R. 385 at 416, L'Heureux-Dubé, J., wrote:
>
> > [A] judge's fundamental consideration in statutory interpretation is the purpose of legislation.

[51] The Nova Scotia Court of Appeal reiterated the modern principle of statutory interpretation in *Sparks v. Holland*, 2019 NSCA 3. Farrar, J.A., stated:

> [27] The Supreme Court of Canada and this Court have affirmed the modern principle of statutory interpretation in many cases that “[t]he words of an Act are to be read in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament (*Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27 at ¶21).
>
> [28] This Court typically asks three questions when applying the modern principle. These questions derive from Professor Ruth Sullivan’s text, *Sullivan on the Construction of Statutes*, 6th ed (Markham, On: LexisNexis Canada, 2014) at pp. 9-10.
>
> [29] Ms. Sullivan’s questions have been applied in several cases, including *Keizer v. Slauenwhite*, 2012 NSCA 20, and more recently, in *Tibbetts*. In summary, the Sullivan questions are:
>
> 1. What is the meaning of the legislative text?
>
> 2. What did the Legislature intend?
>
> 3. What are the consequences of adopting a proposed interpretation?
>
> [Sullivan, pp. 9-10]

[52] As discussed in the reasons of the majority in the Supreme Court of Canada's decision in *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65, these principles also apply to administrative decision makers to require that legislation be interpreted consistent with its text, context and purpose. However, the form of analysis may look different than one undertaken by a court and may be enriched by the specialized expertise and experience of the decision maker:

> [117] A court interpreting a statutory provision does so by applying the "modern principle" of statutory interpretation, that is, that the words of a statute must be read "in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the Act, the object of the Act, and the intention of Parliament": *Rizzo & Rizzo Shoes Ltd. (Re)*, [1998] 1 S.C.R. 27, at para. 21, and *Bell ExpressVu Limited Partnership v. Rex*, 2002 SCC 42, [2002] 2 S.C.R. 559, at para. 26, both quoting E. Driedger, *Construction of Statutes* (2nd ed. 1983), at p. 87. Parliament and the provincial legislatures have also provided guidance by way of statutory rules that explicitly govern the interpretation of statutes and regulations: see, e.g., *Interpretation Act*, R.S.C. 1985, c. I-21.
>
> [118] <u>This Court has adopted the "modern principle" as the proper approach to statutory interpretation, because legislative intent can be understood only by reading the language chosen by the legislature in light of the purpose of the provision and the entire relevant context: Sullivan, at pp. 7-8. Those who draft and enact statutes expect that questions about their meaning will be resolved by an analysis that has regard to the text, context and purpose, regardless of whether the entity tasked with interpreting the law is a court or an administrative decision maker.</u> An approach to reasonableness review that respects legislative intent must therefore assume that those who interpret the law — whether courts or administrative decision makers — will do so in a manner consistent with this principle of interpretation.
>
> [119] Administrative decision makers are not required to engage in a formalistic statutory interpretation exercise in every case. As discussed above, formal reasons for a decision will not always be necessary and may, where required, take different forms. And even where the interpretive exercise conducted by the administrative decision maker is set out in written reasons, it may look quite different from that of a court. The specialized expertise and experience of administrative decision makers may sometimes lead them to rely, in interpreting a provision, on considerations that a court would not have thought to employ but that actually enrich and elevate the interpretive exercise.
>
> [120] <u>But whatever form the interpretive exercise takes, the merits of an administrative decision maker's interpretation of a statutory provision must be consistent with the text, context and purpose of the provision. In this sense, the usual principles of statutory interpretation apply equally when an administrative decision maker interprets a provision.</u> Where, for example, the words used are "precise and unequivocal", their ordinary meaning will usually play a more significant role in the interpretive exercise: *Canada Trustco Mortgage Co. v. Canada*, 2005 SCC 54, [2005] 2 S.C.R. 601, at para. 10. Where the meaning of a statutory provision is disputed in administrative proceedings, the decision maker must demonstrate in its reasons that it was alive to these essential elements.

> [121] The administrative decision maker's task is to interpret the contested provision in a manner consistent with the text, context and purpose, applying its particular insight into the statutory scheme at issue. It cannot adopt an interpretation it knows to be inferior — albeit plausible — merely because the interpretation in question appears to be available and is expedient. The decision maker's responsibility is to discern meaning and legislative intent, not to "reverse-engineer" a desired outcome. [Emphasis added]

[53] The Board must also have regard to the *Interpretation Act*, R.S.N.S. 1989, c. 235, including ss. 9(1) and 9(5):

> **9(1)** The law shall be considered as always speaking and, whenever any matter or thing is expressed in the present tense, it shall be applied to the circumstances as they arise, so that effect may be given to each enactment, and every part thereof, according to its spirit, true intent, and meaning.
>
> **9(5)** Every enactment shall be deemed remedial and interpreted to insure the attainment of its objects by considering among other matters
> (a) the occasion and necessity for the enactment;
> (b) the circumstances existing at the time it was passed;
> (c) the mischief to be remedied;
> (d) the object to be attained;
> (e) the former law, including other enactments upon the same or similar subjects;
> (f) the consequences of a particular interpretation; and
> (g) the history of legislation on the subject.

6.0 SETTLEMENT AGREEMENT

6.1 Settlement Agreement by the Parties

[54] Two Settlement Agreements were filed with the Board during this proceeding. On September 16, 2022, NS Power filed a Settlement Agreement reached between the Utility and various telecommunications carriers proposing a revised pole attachment fee compared to that originally proposed in the GRA. This Settlement Agreement, and the issues about the pole attachment fee, are described in greater detail later in this decision.

[55] On November 24, 2022, NS Power filed a Settlement Agreement with the Board resolving many of the issues in the GRA between the Utility and Intervenors representing most of NS Power's customers (GRA Settlement Agreement). The GRA Settlement Agreement was signed by the CA, SBA, Industrial Group, the MEUs, the

Affordable Energy Coalition, the Ecology Action Centre and Dalhousie University. In addition to agreeing on many issues canvassed in the GRA, the parties agreed that, with the Board's approval, the average rate increase across all customer classes would be 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024. The terms of the settlement were set out in a schedule to the agreement which provided as follows:

Terms of Settlement

It is acknowledged that, subject to Board approvals, rate increases other than those identified below may occur prior to the effective date of the next general rate application in relation to Board-approved AA/BA Riders or other deferred amounts.

GRA Element	Settlement Terms
Potential Deferral Relief	- The parties agree that these Terms of Settlement do not bar NS Power from applying to the Board to defer costs during the Test Years 2023 and 2024, consistent with the *Public Utilities Act* RSNS 1989, c. 380, as amended, and that all parties will be free to take any position they wish with regard to any such application. Any costs proposed to be deferred, and the allocation and amortization of such costs, would be subject to review and decision by the Board at that time.
Deferral / Regulatory Asset Financing Costs	- All financing costs for deferrals are to be calculated using rates equivalent to NS Power's approved Weighted Average Cost of Capital (WACC), as approved by the Board from time to time, or as otherwise directed by the Board.
Overall Rate	- The average rate increase across all customer classes will be 6.9% in each of 2023 and 2024 (see anticipated revenue increase table attached as Schedule "B") with the implementation of an AA/BA Rider in each of 2024 and 2025 to recover historical under-recovered fuel costs. - As the rate increase required to collect under-recovered fuel amounts in a 2024 AA/BA Rider is material for all or certain of the customer classes, the parties will work in a good faith manner to defer a portion of the impact of the increase and costs to 2025 or an additional period as may be reasonable and appropriate. NS Power will apply in October 2023 to set the AA/BA rider for 2024. For greater certainty, as the four Wholesale Market customers (the MEUs) were not FAM customers during the 2020-2022 period, none of the historical under-recovered fuel costs on account of 2020-2022 will be recoverable from those customers.

Non-fuel Rate	- The non-fuel components of the 6.9% average increase in each of 2023 and 2024 consist of the following: - 2023: average 5.4% (1.8% non-fuel and 3.6% DSM) - 2024: average 0.3% (DSM)
Fuel Rate	- The fuel component of the 6.9% average increase in each of 2023 and 2024 consists of the following: - 2023: average 1.5% - 2024: average 6.6% and an AA/BA Rider for historical under-recovery
Decarbonization Deferral Account (DDA)	- The parties agree in principle to a DDA to recover undepreciated thermal asset NBV and unrecovered decommissioning costs and further agree to engage constructively in a consultative process to confirm the practice and procedures that will be followed to establish the DDA and its scope, to effect the transfer of unrecovered costs to a regulatory asset and to recover such costs. The consultative process will be undertaken and completed in such a manner that will result in NS Power providing a report to the Board with the results of the consultative process and seek approval of the DDA by June 30, 2023. For greater certainty, the Board's decision in 2012 NSUARB 133 with respect to the MEUs responsibility for the payment of stranded costs continues to apply and is not affected by this agreement in principle. - The parties also agree to discuss the potential for the application, approval, and implementation of the DDA, or similar mechanism, as it relates to "New Capital Assets" and "Incremental/Decremental OM&G" as those are described in Section 4.1 of NS Power's Rebuttal Evidence (i.e. energy transition investment and costs related thereto).
Equity Ratio	- An equity thickness of 40% for rate setting purposes.
Return on Equity	- A return on equity of 9.0% for rate setting purposes.
Earnings Sharing Mechanism	- NS Power's request for a revised Earnings Sharing Mechanism is withdrawn.
Earnings Band	- An earnings band of 8.75% to 9.25% return on equity on an actual five-quarter average equity ratio of up to 40%.
Customer Charge	- As applied for, but at the 2023 customer charges amount with an agreed to reduction of 25 percent of the proposed increase and no-phase in given there will only be a one-time non-fuel/non-DSM rate increase. (Per Figure 12-2, page 99 of Direct Evidence but with 25 percent reduction to the proposed increase: Domestic Tariffs $19.17/month; Small General $21.28/month.)
Interruptible Rider	- As applied for, but at the 2023 credit amount. (Per Direct Evidence PR-01 Attachment 1, page 38: $7.486/kVa.) - The Interruptible credit will be reviewed in the next Cost of Service Study.

Distribution Adder	-	As applied for, but at the 2023 amount. (Per Direct Evidence PR-01 Attachment 1, page 35: $1.632/kVa.)
Storm Rider	-	For purposes of the years 2023, 2024, and 2025 only, as applied for, per Storm Cost Recovery Rider Direct Evidence PR-01 page 106 and PR-01 Att1v, but, modified as per Section 13 of NS Power's Rebuttal Evidence, to eliminate the volume provision of the Balance Adjustment from the Storm Rider.
	-	The parties agree that NS Power will have the option to apply to the Board for recovery of costs through the Storm Rider in the event that Level 3 and Level 4 storm restoration expense exceeds $10.2 million in 2023, $10.4 million in 2024, and $10.4 million in 2025. The Storm Rider terminates after recovery of costs from 2025.
DSM Rider	-	Implementation of the DSM Cost Recovery Rider (DSM Rider) as it was applied for, but with the amendment set out in Section 13 of NS Power's Rebuttal Evidence such that NS Power, rather than EfficiencyOne, will make the annual application for the DSM Rider to the Board and further amended to remove the last two bullets on page 8 of the DSM Rider, as committed to in the oral hearing and in Undertaking U-40. In addition, the DSM Rider charge will be incorporated within the class energy charges (i.e. not segregated on customer bills). For greater certainty, the DSM Rider's allocation of costs to customers shall be consistent with E1's approved 2023-2025 Application. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be through direct billing by NS Power to such customers.
Misc. Charges (incl AMI opt-out, Pole Attachment Fees, Distribution Tariff, and OATT)	-	As applied for with the exception of Pole Attachment Fees that are to be approved as per Settlement Agreement (Exhibit N-138), and the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum increase of 1.8% in 2023 and 0% in 2024. With respect to the CBAS recommendations proposed by WKM Energy Consultants, the parties agree that these issues will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on these issues, following which NS Power and other parties as they see fit will have the opportunity to file a reply.
ML Transmission Asset Approvals	-	Approval of CI 43324, CI 43678, CI 45066, and CI 45067 for inclusion in rate base at their net book value as of the effective date of the Board's decision on this matter.
GRA Deferral	-	NS Power's request for a GRA Deferral is withdrawn.

Line Loss Study and COSS	-	NS Power must file a Cost of Service Study and a Line Loss Study prior to filing its next GRA or December 31, 2025, whichever is sooner. NS Power will provide for stakeholder engagement in the scoping and review of initial results, which will include consideration of bundled and unbundled services in an integrated manner as referenced in the Board's decision at para. 142 in 2021 NSUARB 126, prior to filing the final Studies. Board approval for the use of those Studies should occur as a part of the next GRA proceeding. Costs associated with the production, stakeholder engagement, and filing of these Studies may be deferred by NS Power and, subject to Board
		approval, recovered through rates subsequent to NS Power's next general rate application.
BUTU GHG Credit	-	With respect to the Wholesale Market Backup/Top-up Service Tariff GHG Credit as proposed in the evidence of Mr. Dominie, the parties agree that this issue will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on this issue, following which NS Power and other parties as they see fit will have the opportunity to file a reply

[Exhibit N-155, pp. 7-10]

[56] The GRA Settlement Agreement also contained an additional schedule showing the anticipated percentage revenue increases per customer class, subject to being confirmed in a compliance filing (see Appendix B).

6.2 The Board's approach to settlement agreements

[57] In its previous decisions, the Board has set out the principles it applies in its consideration of settlement agreements. Those principles bear repeating. In its decision dated November 5, 2008, about a prior NS Power general rate application, the Board outlined its general approach to settlement agreements submitted to it for approval:

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.

> [14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.
>
> [15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.
>
> [16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.
>
> [17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.
>
> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.
>
> [2008 NSUARB 140]

[58] The GRA Settlement Agreement in this proceeding was reached by the parties after the hearing was finished. This matter had a full evidentiary record containing over 30,000 pages of information and spreadsheets, including NS Power’s application, Rebuttal Evidence, Fuel Update, 19 expert reports and documents filed by the Intervenors and Board Counsel consultants, 700 Information Requests (IRs) with over 1,900 questions to NS Power and 157 IRs with over 270 questions to Intervenors, about 1,000 letters of comment from members of the public, almost 300 exhibits, and 71 Undertakings filed after the hearing.

[59] The Board remains mindful that in its consideration of settlement agreements its ultimate duty is to ensure that the terms of agreement are just, reasonable and in the public interest:

> [23] …Settlement agreements do not, however, diminish the Board's duty and obligation to ensure that the terms of any such agreement result in approval of only those costs which are fair, justifiable and prudently incurred by the Utility. Further, the Board must ensure that these costs result in customer rates that are just, reasonable and in the public interest. In addition, when deciding whether to approve a settlement agreement, the Board must be satisfied that the outstanding concerns of all intervenors are adequately considered by the Board and the terms and conditions under which they consent to a settlement agreement are honoured.
>
> [*NS Power 2007 GRA* decision, 2007 NSUARB 8]

[60] While the following submission was made in the context of the Pole Attachment Fee Settlement Agreement, the Board endorses and adopts the comments in Robert Grant and Leslie Milton's Closing Brief about the important role of settlement negotiations in such proceedings:

> 26. … It is in the public interest to approve settlement agreements in these circumstances in order to encourage a collaborative approach to ratemaking. Doing so provides incentive to parties to be reasonable and promotes the reduction of controversy in rate applications coming to the Board.
>
> [Eastlink/Rogers/Xplore Closing Brief, p. 7]

[61] In the Board's view, these comments are particularly relevant in the unique circumstances of this general rate application, which raised challenging issues for NS Power and its customers in the context of the need to tackle the energy transition and the impact of the limitations imposed by Bill 212.

7.0 ANALYSIS AND FINDINGS

7.1 Should the GRA Settlement Agreement be approved?

[62] Before embarking on its review of the merits of the GRA Settlement Agreement, the Board takes note of what Nancy Rubin, counsel for the Industrial Group and Dalhousie University, described as "the unique context of the settlement agreement", given that it occurred after the hearing, rather than before, and that it responded in part to legislation:

> **The Unique Context of this Settlement Agreement**
>
> This is not the Settlement Agreement that would have been reached after the filing of evidence and responses to IRs. This is not the Settlement Agreement that would have been filed after nine days of hearings and the filing of undertakings by NSPI on October 14. This is a Settlement Agreement to which the parties have been driven by the timing of legislative amendments to the ***PUA*** through Bill 212.
>
> Draft closing arguments based on the evidence and responses to undertakings were scrapped. Dalhousie University and the Industrial Group could not ignore the material impact that Bill 212 has had on the evidence and it is within that context that the parties negotiated the Settlement Agreement.
>
> [IG/Dalhousie Closing Submission, p. 3]

[63] This observation was echoed by the Affordable Energy Coalition, which noted that in response to Bill 212 it had signed the GRA Settlement Agreement to “ensure a functioning reliable electricity system, environmental goals are met and affordability” and to mitigate unintended consequences like the impact on NS Power’s credit rating:

> **2. Affordability and the Settlement Agreement**
>
> The AEC signed the Settlement Agreement which limits profits to current levels in accordance with Bill 212. While we argued in our Opening Statement that we believe NSPI’s profit level should not only be limited in this way but should be reduced, we signed the Settlement Agreement in view of the disruption created by Bill 212 and its effect on NSPI’s financing. A stable, appropriately financed electricity system is in the interest of every customer including low income customers in order to ensure a functioning reliable electricity system, environmental goals are met and affordability. The Settlement Agreement is intended to contribute to this. Bill 212 undermined the independent regulation of the electricity system, and the unintended consequence was a downgrading in NSPI’s credit rating which will increase future financing costs. In our view this disruption undermined our ability to argue for reduced profit levels at this time. In future GRA hearings we expect that we will be able to make that argument again.
>
> [Affordable Energy Coalition, Closing Statement, pp. 2-3]

[64] As noted above, the GRA Settlement Agreement obtained broad support from all major customer classes, as well as other parties who participate regularly in matters involving NS Power, including the MEUs (who supported the overall settlement with the exception of a few issues described later in this decision), the Affordable Energy Coalition and Ecology Action Centre. Moreover, most of the signatories filed Closing

Submissions noting the benefits of the agreement and requesting that the Board approve the settlement.

[65] The SBA noted his support for the agreement, asserting that its negotiation involved the balancing of various factors, including current rate affordability and service reliability weighed against meeting decarbonization goals in the future and deferring some fuel costs to later years:

> After the amendments to the *Public Utilities Act* were approved, the SBA began having discussions with NSPI about the Application and what the future might look like. The SBA, as always, was looking for an outcome that would be in the best interests of its rate classes, not only for the short term but also the medium to long term. Small General, General and Small Industrial businesses are the backbone of the Nova Scotia economy. They are impacted by the severe weather and climate change that is impacting our province and want the best for all of Nova Scotia's residents, who represent their customers, their employees and their communities. <u>The SBA believes that it is crucial that they have access to cost-effective, reliable and safe electricity, balanced with the need to reach the decarbonization goals set out by all levels of government.</u>
>
> <u>The Terms of Consensus</u> that has been provided to the Board, signed by the SBA, the Consumer Advocate, counsel for the Industrial Group and Dalhousie University, the Ecology Action Centre and the Affordable Energy Coalition, <u>represents that balance. It balances the need to reduce the increase in 2023 to as low as possible, while also not deferring all the costs to the future, which only increases overall costs.</u> Small business customers need certainty about the future in order to plan their budgets accordingly and the Terms of Consensus provides that. The stable increases, applied first to the DSM increase and then to fuel costs, allows for planning and reduces a deferral of fuel costs. There is a reality that has be acknowledged that costs are increasing across the board and electricity is no different. <u>The Terms of Consensus balances those increases with consistency and smoothing, and ensuring that ratepayers have access to all possible savings through the DDA, Storm Rider and DSM Rider.</u> [Emphasis added]
>
> [SBA Closing Submission, p. 2]

[66] The CA, William Mahody, representing all residential customers, submitted that the agreement offered several positive outcomes for residential ratepayers. He stated that the GRA Settlement Agreement complied with the *Public Utilities Act*, including the Bill 212 amendments. Mr. Mahody noted that the cost pressures from increased fuel expenses led to his support for the agreement:

> The Settlement Agreement represents the outcome of discussions among the vast majority of active participants in this matter, and it has the support of all ratepayer advocates.

> Further, the Settlement Agreement is comprehensive, addressing virtually all of the matters in contention before the Board.
>
> …
>
> Bill 212 received Royal Ascent on November 9, 2022. The discussions leading to the Settlement Agreement commenced after November 9 and all parties to the settlement were aware of the binding nature of that legislation. From the perspective of the Consumer Advocate, the Settlement Agreement was negotiated in compliance with all Statutes, including the *PUA* amendments made via Bill 212.
>
> The evidence at the hearing clearly established that the cost of fuel is exerting tremendous pressure on customer rates. That pressure will continue throughout the test period. It is that fuel cost pressure that led the Consumer Advocate to support the proposed Settlement Agreement in which the lion share of the rate increase is fuel related.
>
> …
>
> In addition to the rate increase caused by known fuel costs, the Settlement Agreement provides for the 1.8% increase referenced in Bill 212. A fair reading of the record in this proceeding – factoring in all reasonably achievable reductions to the applied for revenue requirement – led the Consumer Advocate support the 1.8% referenced in the Settlement Agreement.
>
> [CA Closing Submissions, pp. 3 & 5]

[67] The only party opposing the GRA Settlement Agreement was the Province. NRR's counsel submitted:

> 43. Bill 212 was introduced to protect ratepayers from significant shock based on unprecedented global inflationary pressures, as confirmed in the Premier's letter to the Board dated November 28, 2022. The terms of the Settlement Agreement increase rates and contravene the purpose, spirit, and intent of Bill 212.
>
> 44. Prior to the GRA proceeding, NSP returned a minimum of $125 million in profits each year for the last 12 years. These profits benefit NSP's shareholders but offer no direct benefit to ratepayers. NSP's original position in the GRA proceeding, if granted, would have further inflated these profits.
>
> 45. During harsh economic times, it is unreasonable to impose further hardship on ratepayers to enhance corporate returns. Corporate social responsibility calls for a sharing of the burden to maximize relief for ratepayers for the cost of an essential service.
>
> 46. To this end, NRR has concerns with several specific aspects of NSP's application, and the proposed resolution of these aspects by way of the Settlement Agreement.
>
> [NRR Closing Submissions, p. 9]

[68] NRR submitted that, in a number of respects, the settlement did not comply with Bill 212. In NRR's view, the use of incremental DSM costs since the last GRA, in the

proposed rate increases for 2023 and 2024, is contrary to the requirement to limit non-fuel rate increases to 1.8% over the test years.

[69] Some active participants in the proceeding did not sign the GRA Settlement Agreement, but did not oppose it, including PHP, Eastward Energy, EfficiencyOne, and Freeman Lumber.

[70] In its Closing Submission, NS Power said that the GRA Settlement Agreement should be approved:

> While a settlement agreement does not displace the Board's duty of ensuring just and reasonable rates or that the settlement is otherwise consistent with the relevant legislation, a settlement agreement such as that currently before the Board, which is comprehensive in nature and "widely supported by various parties to the proceeding," including representatives of residential, commercial, and industrial customer classes, should be given significant weight. In previous proceedings, the Board has been satisfied that settlement agreements are properly supported and are in the public interest.
>
> This wide support for the Settlement Agreement is evidenced by its signatories, which include representatives from all customer classes, as well as broadly scoped interest groups such as the Ecology Action Centre and the Affordable Energy Coalition. The diversity of interests is not only as between NS Power and its customers, but also among the customer classes and interest groups who are parties to the Settlement Agreement.
>
> Based on the comprehensive nature of the agreement and the support across all customer classes and interest groups, there should be no question that the Settlement Agreement "is in the best interest of ratepayers." The Board has previously discussed this point, finding that, where an "[a]greement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest."
>
> In considering the Settlement Agreement, the Board must also consider how the public interest is served by regulatory certainty and the value and importance of encouraging settlement discussions and agreements between parties with matters before the Board. …
>
> …
>
> Within the confines of the PUA Amendments, the Settlement Agreement provides a comprehensive agreement on the GRA from representatives of all customer classes and broad interest groups, all of which have a tremendous amount of experience in NS Power's matters before the Board. NS Power views the breadth and experience of the parties who are signatories to the Settlement Agreement, and the enactment of the PUA Amendments, as sufficient evidence of the just and reasonable nature of the Settlement Agreement; …
>
> [NS Power Closing Submission, pp. 9-10]

7.1.1 Findings

[71] The Board's overarching consideration in the review of the GRA Settlement Agreement, including the proposed rates and all other issues covered in it, is whether approving it results in rates that are just and reasonable, non-discriminatory and in the public interest.

[72] An appropriate starting point for the Board's review is to consider the overall context underlying the GRA Settlement Agreement presented by the Utility. The signatories to the agreement included the representatives of all major customer classes representing most of NS Power's customers, as well as other parties who participate in various NS Power matters before the Board. A number of these representatives have significant experience in proceedings involving NS Power at the Board, including general rate applications, fuel matters and the FAM Audit, annual capital expenditure (ACE) applications, annually adjusted rates, proceedings involving DSM and EfficiencyOne, the Maritime Link, rates like the BUTU, Shore Power, and the ELIADC, and renewable matters like COMFIT, renewable energy procurements, Renewable to Retail, and the NS Power Smart Grid pilot project, among other proceedings. The Board is mindful that this experience has provided these parties and their representatives with a broad understanding of NS Power, its infrastructure, and its operational realities.

[73] Moreover, the GRA Settlement Agreement represents a comprehensive resolution of many complex issues raised in this GRA, with only a few exceptions involving the MEUs remaining outstanding. Despite these outstanding issues, the MEUs executed the GRA Settlement Agreement on all other points covered by the settlement. The broad range of issues settled among the parties, considered in conjunction with the signatories

representing most of the customers joining the settlement, provides greater confidence to the Board that approving it would be in the public interest.

[74] A subtle corollary to the broad support for the GRA Settlement Agreement, and the comprehensive nature of the resolved issues, is the support the parties have provided to NS Power by reaching a negotiated settlement that attempts to address regulatory and financial concerns raised by the introduction of Bill 212 and the reaction of the credit rating agencies. While many of the Intervenors often challenge NS Power in various proceedings, including in this GRA, some of the parties stated that it was important to reach a comprehensive settlement to help ensure that NS Power remains a healthy utility, particularly as it embarks on the phase out of coal and strives to increase renewables on its system. The comprehensive settlement confirms rates that also recover increased fuel costs, introduces the FAM Riders to recover deferred fuel costs, adopts the DSM Rider and Storm Rider, confirms the Utility's return on equity needs, and supports in principle the creation of a DDA to address the realities of the upcoming energy transition. At the very least, the broad support on a wide range of issues demonstrates that NS Power had a constructive discussion with its customer representatives.

[75] The Province submits that various elements of the GRA Settlement Agreement do not comply with the recent *Public Utilities Act* amendments introduced in Bill 212. Clearly, the Board must not approve any settlement agreement that does not comply with all applicable statutes. As discussed later in this decision, the Board has found that the GRA Settlement Agreement does comply with all statutory provisions.

[76] In the Board's view, there are various aspects of the GRA Settlement Agreement that warrant approval. All of these will be discussed in greater detail later in this decision.

[77] First, the Board is satisfied that the negotiated average rate increases across all customer classes of 6.9% in each of 2023 and 2024 are reasonable and appropriate. The Board also finds that it is reasonable to defer part of the increased fuel costs to later years. The Board is keenly aware that any rate increase has an impact on ratepayers, particularly low-income customers and those on a fixed income. No rate increase is ever welcomed by ratepayers. However, the Board places significant weight on the fact that all major customer classes have negotiated these rate increase levels.

[78] It is also significant that the Affordable Energy Coalition finds the negotiated rate increases to be appropriate in the circumstances, noting the importance to low-income customers of a healthy utility. The negotiated settlement with its customer classes helps to ensure that NS Power remains a healthy utility, which is important to maintain its ability to provide reliable service and to attract capital investment for the energy transition from coal to more renewables.

[79] The request for increased rates by the Company, and the amount of the negotiated increase, must also be considered in the context that NS Power has not had a non-fuel rate increase since 2014. During the period 2014 to 2022, inflation has risen over 20%. Moreover, various federal and provincial environmental provisions require NS Power to retire coal assets and invest in infrastructure to meet 80% renewable goals by 2030 and net-zero GHG emissions requirements by 2050. While the composition of the rates is discussed later in this decision, the negotiated rates account for increased DSM

spending levels and a portion of increased fuel costs. In the Board's opinion, the introduction of the FAM Riders in 2024 and 2025 provides an appropriate balance between managing rate increases in the near future and ensuring that NS Power will be able to recover its fuel costs in a reasonable time span, bearing in mind that it may still be necessary to manage the rate impacts from implementing the riders in these years. Against that background, the Board finds that, as part of the total negotiated package in the GRA Settlement Agreement, the requested average rate increases of 6.9% in each of 2023 and 2024 are reasonable.

[80] Second, the GRA Settlement Agreement confirms NS Power's opportunity to earn a reasonable return, consistent with the regulatory compact enshrined in the *Public Utilities Act* and in the case law. Again, this is important so that the Company can attract capital to invest in its infrastructure, including more renewables. The current return on equity of 9.0% and the earnings band of 8.75% to 9.25% have been maintained, with the equity thickness for rate setting purposes being increased from 37.5% to 40%. The current Earnings Sharing Mechanism has also been kept, with excess earnings being refunded to ratepayers through the FAM, as is the case already.

[81] Third, the GRA Settlement Agreement provides an agreement in principle on the creation of a DDA, at least with respect to NS Power's thermal assets. The Board finds that this initiative is an appropriate one and in the best interests of the Utility and its customers as they engage in the energy transition. It will help enhance the transparency of the task ahead as NS Power is required by legislation to retire its thermal plants by 2030. The creation of the DDA will clearly segregate and track the financial costs associated with retiring those plants.

[82] Moreover, the creation of a DDA will allow for regulatory efficiency and provide greater flexibility to the Board to balance the cost recovery of plant retirements and decommissioning costs and affordability issues for the Utility's customers. There will not be any rate impacts in the near term from the approval in principle of the DDA.

[83] The customer representatives' support, in principle, for the establishment of a DDA, and the associated stakeholder consultation, demonstrates that there is a broad recognition of the need for a collaborative approach to the energy transition. Indeed, in its December 20, 2022, report, DBRS Morningstar noted that it would look favorably on "meaningful progress on the replacement of coal-fired plants with renewable sources in order to meet the mandated targets". The Board is pleased there is a constructive dialogue taking place in Nova Scotia about the impact on the Utility and its customers of a future without coal and other fossil fuels.

[84] Fourth, the Board also considers the establishment of the Storm Cost Recovery Rider (Storm Rider) and DSM Cost Recovery Rider (DSM Rider) as appropriate. The Storm Rider allows the recovery of all reasonable costs related to Level 3 and Level 4 storms. It is only a three-year pilot, but this will allow the parties to observe its effectiveness. It also allows an additional opportunity for assessment of system reliability and service restoration times, which are important concerns for all customers. Similarly, the establishment of a DSM Rider will provide certainty to the Utility that the costs incurred for EfficiencyOne will be recovered in a transparent way.

[85] Further, the Board considers it to be a positive outcome of the settlement process that the parties to the GRA Settlement Agreement were able to agree upon changes to various fees and amounts in NS Power's schedule of fees and charges,

including a 25% reduction to the proposed customer charges for Domestic and Small General Class customers; the addition of a Distribution Adder and an increase to the credit amount in the Large Industrial Interruptible Rider; revisions to the Distribution Tariff; and a cap of the maximum increase to the OATT of 1.8% in 2023 and 0% in 2024. Again, the agreement of the parties on such a variety of changes demonstrates that NS Power has had a productive engagement with its customer class representatives and it warrants the support of the Board.

[86] Following the filing of a large amount of evidence by NS Power and the Intervenors on cost allocation methodologies and line loss matters, the parties to the GRA Settlement Agreement agreed to defer the issues to a stakeholder engagement process, followed by the Utility filing an updated Cost of Service Study and Line Loss Study prior to the next GRA or by December 31, 2025, whichever is sooner. This recognized that there are complex issues requiring further examination by the parties. Such engagement should be supported.

[87] Taking into account the evidence and the submissions, the Board is satisfied that, considered in its totality, the GRA Settlement Agreement is in the public interest and it should be approved, except for three items discussed below. In the Board's view, the agreement provides for rates that are just and reasonable and is an appropriate resolution of many issues canvassed in the GRA. The Board also finds that the agreement complies with the requirements of Bill 212.

[88] As discussed later in this decision, the Board does not approve three items in the GRA Settlement Agreement. It does not approve NS Power's proposed AMI opt-out fee or the regulatory amortization of the Annapolis Tidal Generation Facility, which is

to remain in rate base. Further, the Board defers approval of the four Maritime Link transmission capital projects until benefits to ratepayers have been demonstrated. The Board finds these three matters are not material to the comprehensive settlement reached by the parties. NS Power may re-apply to the Board for approval of these items once conditions are met or circumstances warrant.

7.2 Interest on Deferrals

[89] The GRA Settlement Agreement provides that:

> All financing costs for deferrals are to be calculated using rates equivalent to NS Power's approved Weighted Average Cost of Capital (WACC), as approved by the Board from time to time, or as otherwise directed by the Board.
>
> [Exhibit N-155, Schedule A, p. 8]

[90] This must be considered under s. 64AB of the *PUA*, which was recently added by Bill 212:

> **Payment of interest**
>
> **64AB (1)** The Board may approve the payment of interest to Nova Scotia Power Incorporated on an outstanding balance for the Fuel Adjustment Mechanism, or any other regulatory deferral.
>
> **(2)** To be eligible for a payment of interest under subsection (1),
>
> (a) Nova Scotia Power Incorporated must demonstrate a balance is outstanding, or there is a clear demonstrated prediction for an outstanding balance, for a period of not less than twelve months prior to a request for the payment of interest; and
>
> (b) the minimum amount on an outstanding balance must be greater than one million dollars.
>
> **(3)** Interest must be calculated
>
> (a) from the date the balance is outstanding using simple interest at the Bank of Canada policy interest rate plus one and three-quarters per cent, unless otherwise directed by the Board; and
>
> (b) on a per year basis.

(4) Any request for the payment of interest on an outstanding balance must include the interest calculations for the Board for review.

[91] In response to NSUARB IR-1 (GRA Settlement Agreement) [Exhibit N-156], NS Power identified the regulatory assets and regulatory liabilities for which it seeks Board approval to recover financing costs at its Weighted Average Cost of Capital (WACC):

	Forecast Ending Balance			Forecast Average Balance	
($ Million)	**2022**	**2023**	**2024**	**2023**	**2024**
FAM Deferral	141.0	262.8	146.5	201.9	204.7
DSM Deferral	5.0	-	-	2.5	-
Renewable to Retail	1.3	1.3	1.4	1.3	1.4
Retired Hydro Assets (Harmony & Roseway, Annapolis)	22.7	20.1	17.6	21.4	18.9
Deferred Income Taxes	10.9	26.6	26.6	18.8	26.6
Total Regulatory Assets and Liabilities	**180.9**	**310.8**	**192.1**	**245.9**	**251.5**

[92] The Board notes that in the reproduction above, it has removed the rows in the table for the recovery of deferred GRA costs and the DDA, and the totals have been adjusted accordingly. Under the GRA Settlement Agreement, NS Power agreed to withdraw its claim for the recovery of deferred GRA costs, which it had shown as having no balances as a result. The removal of the DDA balances is discussed below. The deferred balance for the Annapolis Tidal Generation Facility, which is consolidated in retired hydro assets in the table, is also discussed below.

[93] NS Power is also requesting financing costs at its WACC for balances under the DSM Rider and the Storm Rider, and for the costs that the parties to the settlement agreed should be deferred for the Line Loss and Cost of Service Studies.

[94] In the NSUARB IR-1 (GRA Settlement Agreement) response, NS Power addressed why the Board should exercise its discretion under s. 64AB to allow financing costs on deferrals at NS Power’s WACC. NS Power noted that its forecast WACC is the expected actual cost of financing investments based on its approved capital structure for

ratemaking purposes following a cost of service model. It said that regulatory assets and liabilities form part of its rate base, to which it is entitled to a just and reasonable return under s. 45 of the *PUA*. It also said the use of WACC is accepted utility practice, was well established in Nova Scotia and reflects the regulatory compact. NS Power submitted that, to the extent that the Board has discretion to determine a different interest rate, this must be exercised "within the confines of the statutory regime and principles generally applicable to regulatory matters, for which the legislature has assumed to have regard in passing that legislation" (*ATCO Gas and Pipeline Ltd. v. Alberta (Energy & Utilities Board)*, 2006 SCC 4).

[95] NS Power also noted that the interest rate in s. 64AB was less than its cost of issuing new long-term bonds, meaning that if the Board determined that a deferral at that interest rate was in the best interest of customers, NS Power would be recovering less than its actual financing costs even if it were able to fund the deferral entirely with debt. It further noted that it is not able to fund deferred costs entirely with debt given the impact on its credit metrics, the potential for further credit downgrades and debt covenants in place with its bondholders limiting the percentage of debt it can have in its capital structure.

[96] NS Power advised that it must "update its GRA forecasting to reflect the decreased equity financing and increased debt financing required as a result of the legislative amendment to Section 64AA to complete its calculation of financing costs on requested deferrals."

[97] In discussing s. 64AB in its Closing Submission, NRR said the amendment was intended to make interest returns accruing from NS Power's deferrals more

accountable to the Board and more transparent to ratepayers. NRR submitted that the amendment "permits NSP reasonable interest on legitimate deferrals, while disincentivizing unnecessary deferrals on which ratepayers will be expected to pay interest."

[98] In its Reply Submission, NS Power submitted that NRR had not challenged the position or justification for its request that the Board approve financing costs for deferrals at its WACC in NSUARB IR-1 (GRA Settlement Agreement). NS Power then went on to repeat and elaborate on what it said in IR-1:

> In its response to NSUARB Settlement Agreement IR-1, NS Power provided the following:
>
> > <u>The Bank of Canada policy interest rate plus 1.75 percent included in the legislative amendments is less than NS Power's cost of issuing new long-term bonds.</u> The November 21, 2022 credit rating downgrade received by NS Power from S&P Global in response to the impacts of Bill 212 is expected to further increase NS Power's debt financing costs. <u>This means that if the Board were to determine that a deferral of costs by NS Power to be recovered in the future was in the best interest of customers, NS Power would be recovering less than the Company's financing costs, even if the Company were able to fund the deferral entirely with debt.</u>
> >
> > However, NS Power is unable to fund deferred costs entirely with debt. Given NS Power's credit downgrade by S&P Global, increasing debt would put further pressure on the Company's credit metrics and risk further downgrades. NS Power's credit rating is now at the lowest level considered to be investment grade; a further downgrade would have significant impacts on NS Power's ability to attract capital and the borrowing costs to be borne by customers. In addition, the Company has debt covenants in place with bondholders which limit the percentage of debt that the Company may have in its capital structure. As a result, NS Power is unable to materially increase the level of debt in its capital structure and must finance its investment in the Company within the Board-approved capital structure range.
> >
> > Like all companies, NS Power must pay its operating costs, including interest expense, before determining the amount of net income attributable to common shareholders. As NS Power would be paying more than the amount included in revenue requirement for interest expense under a scenario in which NS Power receives the Bank of Canada policy interest rate plus 1.75 percent on deferred costs, the financing costs included in revenue requirement remaining and attributable to common shareholders would be at a rate lower than the amount paid by NS Power in interest expense.

> The cost of equity should be higher than the cost of debt, as bondholders have a priority claim on the Company's assets as compared to equity holders. However, under the scenario in which NS Power receives the Bank of Canada policy interest rate plus 1.75 percent on deferred costs, equity holders would receive a lower rate of return than bondholders. Instead of a risk premium, there would be a discounted rate of return on equity as compared to debt.
>
> These are not just or reasonable scenarios. Holding the return of shareholders on deferrals to less than that of a bondholder will inhibit NS Power's access to capital and impair the Company's ability to fund investment in reliability and ongoing operations and to recover fuel costs over an extended period. This would limit the Company's ability to mitigate rate volatility, which NS Power undertakes for the direct benefit of customers. [Emphasis added]
>
> [NS Power Reply Submission, pp. 12-13]

[99] NS Power also submitted that NRR's Closing Submission acknowledged that s. 64AB permitted it to earn reasonable interest and submitted that the provision did not alter the standard created by s. 45 of *PUA.*

7.2.1 Findings

[100] A basic principle of regulation, as noted earlier in this decision, is the ability of a utility to recover its prudently incurred costs. Most of the deferral balances that NS Power is requesting bear financing costs at its WACC in this GRA are costs incurred in its normal course of operations. By definition, the weighted average cost of capital is the actual average carrying cost on each dollar spent, and not immediately collected, by the Utility. Those dollars are provided in part by debt, and in part by equity investment. Similar to the requirement for a down payment in order to obtain a mortgage on a home, debt is not available without the equity investment. NS Power must maintain a certain level of equity investment to comply with the terms of its debt agreements.

[101] In the normal course, balances owing under NS Power's FAM would attract interest at NS Power's WACC. However, the Board has some difficulty with NS Power's suggestion that the Board may exercise its discretion under s. 64AB of the *PUA* to allow

NS Power to recover interest on FAM balances at its WACC based on “accepted utility practice” and the “long-established practice in Nova Scotia.” If that were enough, the Board would always be justified in exercising its discretion to award a different interest rate than the Bank of Canada policy interest rate plus 1.75% specified in s. 64AB(3)(a). This would tend to make the recent amendment meaningless, which the Board cannot assume was the intent. However, the Board finds it is not necessary to consider this question because it is satisfied there is sufficient justification for exercising its discretion to allow interest on NS Power’s existing deferrals at NS Power’s WACC.

[102] The Board believes that approving the rate specified in Bill 212 on all of NS Power’s existing deferrals has the potential to have a further negative impact on NS Power’s credit ratings, and overall financial health. This would not be in the best interests of ratepayers. The Board is of the opinion that this is precisely why the legislation allowed for the Board’s discretion in assigning this rate.

[103] As shown in the table above from NS Power’s response to NSUARB IR-1, the existing deferrals all exceed $1 million, and they will be outstanding for more than 12 months. As such, the Board is satisfied that the requirements under s. 64AB(2) have been met.

[104] In considering the interest rate for these deferrals, the Board finds that NS Power’s recent credit downgrades are a relevant factor because they heighten concerns around NS Power’s credit metrics and the risk of further downgrades, resulting in the potential imposition of even more costs on ratepayers. Credit ratings are a measure of the probability an organization will default on its financial obligations. The recent downgrade of NS Power’s credit ratings commands the Board’s attention. This is an

indication that NS Power's financial health is perceived by the markets to be at a higher level of risk than it was several months ago.

[105] The Board notes NS Power's concern that setting the stated interest rate in Bill 212 on its regulatory deferrals could be setting its return on the equity invested in those balances at a lower rate than its bondholders are receiving. It appears that this would increase the risk to the financial health of the Utility. In this instance, the Board believes that stability and predictability are paramount.

[106] The Board concludes that in the circumstances, it is appropriate for it to exercise its discretion under s. 64AB(3) to set interest on the deferrals in the table above at NS Power's WACC (subject to the comments below about the Annapolis Tidal Generation Facility).

[107] Additionally, there are other reasons why approving interest at NS Power's WACC on FAM balances is appropriate. As discussed later in this decision, NS Power will defer a significant amount of fuel costs it expects to incur so rates are reduced in the current application. The parties have also agreed to discuss potential further deferrals of these costs to manage rate impacts. While it comes at a longer-term cost, the management of these rate impacts is a benefit to ratepayers in the circumstances of this proceeding.

[108] The Board also notes that FAM balances may relate to both over- or under-recoveries. In the case of over-recoveries, the balances are returned to customers with interest at NS Power's WACC. To be equitable, the interest rate paid to customers on over-recoveries and received from customers on under-recoveries should be the same.

[109] Regarding the potential future deferrals for the DSM Rider, the Storm Rider, the DDA, and the Cost of Service and Line Loss Studies, the Board finds that, considering s. 64AB of the *PUA*, the request for interest relating to these items is premature. It is not known whether any balances under the DSM and Storm Riders will exceed $1 million or if they will be outstanding for at least 12 months.

[110] While balances in the DDA would be expected to meet these requirements, as discussed later, the Board accepts the DDA in principle but it is not formally approving a DDA at this time. Any application for interest relating to the DDA should proceed at the time of seeking formal DDA approval and following the agreed upon stakeholder consultative process.

[111] In expert evidence and during the hearing, securitization was presented as a possibility to mitigate the significant carrying costs associated with future retirement of NS Power's thermal plants. The Board sees this as a possibility to reduce the carrying costs on the DDA in the future. However, there is due diligence that would need to be completed to determine if this is a viable option for NS Power, and in the best interests of customers.

[112] Finally, for all the items for which the Board is not approving a rate for the recovery of interest at this time, the circumstances at the time of a future application for interest may be different, particularly relating to NS Power's credit ratings and access to debt financing. This, along with other factors, may have an impact on the exercise of discretion about the appropriate interest rate on deferrals.

[113] In the case of the Annapolis Tidal Generation Facility, and as discussed later in this decision, the Board is not approving the creation of a regulatory asset at this

time as NS Power has not addressed the concerns the Board expressed in denying its previous application to have the facility declared not used and not useful (M10013).

[114] For the existing deferrals approved for the recovery of interest at NS Power's WACC discussed above, the Board directs NS Power to provide forecasted interest calculations to the end of 2024 in its compliance filing.

7.3 2023 and 2024 6.9% rate increases

[115] In a general rate application, NS Power forecasts its costs for the next year, which is referred to as the test year. In an application that seeks to set different rates over multiple years, such as the present proceeding, the forecast covers a number of test years. In either case, the costs in the test years are reviewed in considering the application. If they are reasonable and prudent, they are included in the total costs the Company may recover in the rates it charges to its customers. The revenue needed to cover these reasonable and prudent costs is NS Power's "revenue requirement."

[116] Because the rates charged to customers must be fair, not only as between NS Power and its customers, but also as between NS Power's various customer classes, NS Power's costs are allocated to each class under a cost of service study. Class rates are then designed to recover the portion of costs allocated to that class (i.e., the revenue requirement for that class).

[117] Once rates are set, actual costs will likely vary between rate cases, but rates will not. Rates remain the same until the next general rate application when the Utility's costs in the test year or years at that time will again be used to determine a new revenue requirement upon which new rates will be set.

[118] There are also other factors that influence rates. For example, if a utility's costs remained the same between rate applications, but demand for its services increased, rates would be reduced, everything else being equal. Conversely, reducing demand tends to increase rates if costs remain the same.

[119] NS Power's fuel and purchased power costs are an exception. These costs are recovered under NS Power's approved FAM. As designed, the FAM requires the setting of a base cost of fuel rate at least every two years. Annual adjustments account for the variation between actual fuel and purchased power costs and the fuel related revenues recovered under the base cost of fuel rate. Fuel stability plans covering multiple years have sometimes altered the way this mechanism works but the intent is to ensure that NS Power's customers pay only the reasonable and prudent fuel costs actually incurred.

[120] Figure 10-1 in NS Power's revised application [Exhibit N-16], filed on February 18, 2022, shows its forecast revenue requirement for 2022 ($1,592,800,000), 2023 ($1,685,300,000) and 2024 ($1,665,900,000) by cost category. NS Power's standardized filing requirements for regulated statements of earnings [Exhibit N-20, FOR-01, Attachment 1] has similar information, but also includes the 2014 restatement of NS Power's compliance filing in its last general rate application. Part of FOR-01, Attachment 1, which includes NS Power's restated 2014 compliance filing and its proposed rates in the application (2022-2024), is reproduced below:

Nova Scotia Power Inc. **FOR-01**

Regulated Statements of Earnings
Years Ended December 31st
Millions of Dollars

2022-2024 Financial Outlook

	(1) Compliance Restated 2014	(7) Proposed Rates 2022	(8) Proposed Rates 2023	(9) Proposed Rates 2024
Revenue				
Electric	1,247.8	$1,558.3	$1,649.8	$1,629.7
Other	23.2	34.5	35.4	36.1
Total	1,271.0	1,592.8	1,685.3	1,665.9
Cost of Operations				
Fuel for generation and purchased power	450.7	682.5	683.2	702.7
FAM Fuel Cost Deferral	-	-	52.5	-
Fixed Cost Recovery adjustment	16.5	-	-	-
Rate Stabilization Adjustment	(35.3)	-	-	-
Settlement Adjustment	(13.8)	-	-	-
Cost of goods sold	1.0	-	-	-
Operating, maintenance and general	282.3	283.6	288.8	297.4
Demand Side Management	-	41.0	39.0	39.0
Grants in lieu of property taxes	38.4	42.8	43.5	44.3
Depreciation and accretion	202.2	251.8	265.3	280.4
Total Cost of Operations	942.1	1,301.6	1,372.3	1,363.8
Earnings From Operations	328.9	291.2	312.9	302.1
Regulatory amortization	22.1	11.4	12.1	10.5
Allowance for funds used during construction, FAM and RS interest	(12.4)	(17.9)	(27.2)	(21.7)
Earnings Before Interest and Tax	319.3	297.6	328.0	313.3
Interest and Other expenses	153.1	122.0	121.3	116.3
Earnings Before Income Tax	166.2	175.6	206.7	197.0
Corporate income tax	34.8	22.1	14.4	(16.5)
Net Earnings Before Dividends	131.4	153.4	192.2	213.5
Preferred dividends	8.0	-	-	-
Net Earnings Applicable to Common Shares	**$123.4**	**$153.4**	**$192.2**	**$213.5**

[121] Compared to 2014, NS Power's costs show notable increases in fuel and purchased power, depreciation and accretion, and net earnings (shown as "Return on Equity" in Figure 10-1 [Exhibit N-16]). Although it is dealt with in more detail later in this decision, the Board also notes that no demand side management costs are included in the restated 2014 compliance filing, but they were included in the revenue requirements

for the test years in the current application. Operating, maintenance and general (OM&G) costs are essentially flat from those embedded in 2014 rates to those proposed in 2022 rates. These costs increase slightly through the test period.

[122] There is an uneven distribution of cost increases in the test years. Overall, the revenue requirement increases approximately $320 million from 2014 to 2022, increases nearly $100 million again in 2023 and drops approximately $20 million in 2024. To manage this volatility, NS Power's application proposed rate increases that would be smoothed over 2022-2024 for overall average rate increases of 3.6% in each of the three years.

[123] By the time NS Power filed its Fuel Update on September 2, 2022, its forecast fuel costs had ballooned and were projected to be $681.5 million more than initially forecast in its application. NS Power summarized these changes in Figure 1 in the update [Exhibit N-103]:

Figure 1 – Summary of Fuel and Purchased Power Changes 2022-2024*

Change in Fuel Costs (May 2021 vs June 2022) ($ Million)				
	2022	2023	2024	Total
GRA Total Fuel Costs	682.5	683.2	702.7	2,068.4
Fuel Update Costs	933.5	875.9	940.5	2,749.9
Variance	251.0	192.7	237.8	681.5

* Costs include GHG compliance expense for 2022.

[124] Fortunately, the Province of Nova Scotia provided relief to customers on GHG compliance expenses to the end of 2022, which is expected to reduce the impact of NS Power's fuel cost update by approximately $165 million. Even with this benefit, a large amount of forecast extra fuel costs remains to be addressed. Despite this, NS Power did not propose to adjust the amount of fuel costs to be recovered for 2023 and

2024 from what was sought in the original application. Instead, it proposed to collect under-recovered fuel costs to the end of 2022 over a three-year period from 2023-2025. NS Power also proposed to address the anticipated under-recovery of fuel costs during the test years through annual FAM Riders in 2024 and 2025.

[125] In Undertaking U-2 [Exhibit N-152], NS Power provided a “benchmark proposal” as a frame of reference for comparing some cost recovery scenarios it was asked to produce. The benchmark proposal assumed no rate changes in 2022, a resetting of the smoothing for the 2023 and 2024 base fuel costs (based on the fuel costs for those years in its original application), the smoothed recovery of under-recovered fuel costs to the end of 2022 in 2023-2025, and DSM in the amounts approved in the Board’s *2023-2025 DSM Plan* decision in M10473.

[126] Under the benchmark proposal, overall average rate increases of 6.9% were shown for 2023 and 2024. However, the benchmark proposal would have also required that sizeable adjustments to FAM Riders be considered for the forecasted under-recovery of fuel costs in 2023 and 2024, or a significant projected deferral by 2025.

[127] The parties who signed the GRA Settlement Agreement propose that the Board approve an overall average rate increase of 6.9% in each of 2023 and 2024. This is the same increase shown in the benchmark proposal provided in response to Undertaking U-2, but the share of fuel and non-fuel components is different because of the rate increase limitations in the *PUA* amendments. Like the benchmark proposal, and despite the recovery of more fuel costs, it also leaves a significant amount of forecasted fuel costs unaddressed (including the unrecovered balance to the end of 2022).

[128] NS Power provided information on potential impacts from this deferred recovery of fuel costs in response to NSUARB IR-4 (GRA Settlement Agreement) [Exhibit N-156]. The parties propose that these costs be addressed through the FAM Riders in 2024 and note:

> As the rate increase required to collect under-recovered fuel amounts in a 2024 AA/BA Rider is material for all or certain of the customer classes, the parties will work in a good faith manner to defer a portion of the impact of the increase and costs to 2025 or an additional period as may be reasonable and appropriate.
>
> [Exhibit N-155, p. 8 (PDF)]

[129] The table below compares the fuel, non-fuel and overall average rate increases under NS Power's application, the benchmark proposal in Undertaking U-2 and the GRA Settlement Agreement. As discussed, the table does not account for the recovery of all the fuel costs forecasted in the Fuel Update in either the benchmark proposal scenario or as proposed under the GRA Settlement Agreement. It should also be noted that the non-fuel numbers in the original application assumed DSM costs based upon the approved DSM budget for 2022 and estimated budgets for 2023 and 2024. Higher DSM budgets were approved by the Board after NS Power's application was filed for EfficiencyOne's 2023-2025 DSM Plan (M10473). The higher DSM amounts are included in the Fuel Update and GRA Settlement Agreement rate increases shown:

Rate Component	Application (Smoothed) Figure 2-4 Exhibit N-16 (Estimated DSM 2023-24))			Fuel Update U-2, Figure 12-5, Tab 1 (Benchmark Proposal) Exhibit N-152 (Approved DSM)		Settlement Agreement Schedule "B" Exhibit N-155 (Approved DSM)	
	2022	2023	2024	2023	2024	2023	2024
Non-fuel	2.8%	2.8%	2.8%	5.2%	5.2%	5.4%	0.3%
Fuel	0.8%	0.8%	0.8%	1.7%	1.7%	1.5%	6.6%
Total	3.6%	3.6%	3.6%	6.9%	6.9%	6.9%	6.9%

7.3.1 Overall Increase

[130] The *PUA* amendments place a cap on rate increases in this proceeding, subject to limited exceptions. In its response to NSUARB IR-2 (GRA Settlement Agreement), NS Power explained the approach that it took to develop rates to follow this restriction:

> NS Power reduced each above-the-line (FAM customers) rate class's revenue responsibility for non-fuel costs before the Interruptible Rider Adjustment and allocation of DSM costs proportionately to each class's relative share in the total non-fuel/non-DSM cost revenue requirement before the Interruptible Rider Adjustment and DSM costs as filed in the GRA. This resulted in an overall average 1.8 percent non-fuel/non-DSM rate increase in 2023 and 0 percent in 2024, thereby establishing the revenue requirement for rate-setting purposes pursuant to the amendments to the Public Utilities Act (the capped revenue requirement).
>
> [Exhibit N-156]

[131] In essence, NS Power reduced its revenue requirement for non-fuel and non-DSM costs for rate setting purposes to meet the legislated cap using the costs in its original application. It did not restate those costs to show whether, or how, it might reduce them to achieve the rates being proposed.

[132] In its Closing Submission, NS Power said the proposed rates under the GRA Settlement Agreement produced a forecasted shortfall in non-fuel revenues of $70 million over 2023 and 2024 compared to its benchmark proposal in Undertaking U-2. It submitted that the evidence presented to the Board in this proceeding did not justify such a significant reduction to its revenue requirement.

[133] NS Power relies on the ScottMadden and Gartner studies it filed in this proceeding as demonstrating the reasonableness and prudency of its OM&G costs. NS Power noted these costs were essentially flat between 2014 and 2022 despite inflationary pressures of about 20% through this period. It also noted its forecast for these costs did

not include the high inflationary pressures that have arisen in 2022 since its forecast was prepared.

[134] In his evidence [Exhibit N-55], Board Counsel consultant, Paul Burnell, FSA, FCIA, Plenus Actuaries and Consultants, noted that interest rate levels had increased sharply since the preparation of the pension costs used in the rate application. He said pension costs in the application would be lower at current interest levels. In its Closing Submission, NS Power said it expects that any pension cost savings that may arise from interest rate increases would be more than offset by increased interest expense and the cost effects of inflation, as well as increased financing costs arising from the *PUA* amendments.

[135] The parties who signed the GRA Settlement Agreement supported NS Power's approach to achieving a reduced revenue requirement for rate setting purposes and the proposed rates. In his Closing Submission, the CA said:

> In addition to the rate increase caused by known fuel costs, the Settlement Agreement provides for the 1.8% increase referenced in Bill 212. A fair reading of the record in this proceeding – factoring in all reasonably achievable reductions to the applied for revenue requirement – led the Consumer Advocate [to] support the 1.8% referenced in the Settlement Agreement.
>
> [CA Closing Submission, p. 5]

[136] While they supported the proposed rates, some GRA Settlement Agreement signatories did not fully agree with NS Power's assessment of the impact of the *PUA* amendments on its costs. The Closing Submission filed by the Industrial Group and Dalhousie University noted:

> NSPI's filed GRA was predicated on a certain revenue requirement, with each expense and capital investment broken down and itemized. At this point, NSPI "has not yet determined how resources will be redeployed to comply with the requirements of Bill 212." NSPI has stated that it will need to operate with approximately $70 million in revenue reduction over its forecast.

> With the terms reflected in the Settlement Agreement, the Industrial Group believes that this reduction can be achieved. First, a material portion of the revenue requirement reduction is addressed through the reduction in equity thickness. Additionally, interest rates have continued to rise with a correlative beneficial effect on pension expenses. The evidence was that the dollar value of the reduction in service costs for NSPI's revenue requirement for pensions in 2023 and 2024, based on an increase in interest rates of 1.8% to 2.4% would be $6.8 million to $11.3 million in 2023 and $7.0 million to $11.6 million in 2024. In cross-examination, NSPI agreed with Mr. Burnell's assessment, with its own actuaries confirming those ranges were reasonable. There is also an approximate $3 million reduction in the Maritime Link assessment in 2023, subject to the Board's decision in that application (M10708).
>
> The other lever for NSPI to control costs relates to capital investments and associated return and depreciation. Evidence during the hearing suggested considerable uncertainty with the capital project addition forecast in the GRA to the effect that a number of projects are not yet applied for, or not yet approved. NSPI may choose to manage the timing of these projects, if satisfied they can be deferred without sacrificing reliability.
>
> [IG/Dalhousie Closing Submission, pp. 3-4]

[137] In their Reply Submission, the MEUs stated:

> The MEUs agree that the one-time 1.8 percent non-fuel, non-DSM increase agreed to in the Settlement Agreement is just, reasonable, and prudent in the context of this case. However, NS Power's alleged "forecast shortfall… of approximately $70 million" needs to be understood both in relation to the forecast revenue requirement approved as part of NS Power's most recent 2013/14 General Rate Application ("GRA"), and the differences between NS Power's 2022 GRA forecast as filed and the actual 2022 year-to-date results discussed in the hearing.
>
> [MEUs Reply Submission, p. 4]

[138] The MEUs went on to note that the forecast used to set rates for 2014 varied considerably from the costs that were actually incurred, resulting in an over-recovery of expenses (subject to over-earnings being returned to ratepayers). The MEUs observed that until 2020 and the COVID-19 pandemic, NS Power was able to earn at the top of its earnings range, even after finding room to absorb demand side management costs when the earlier DSM Rider was removed by legislation in 2015. The MEUs then compared NS Power's 2022 GRA forecast to actual results noting again that actual results were better than forecast.

[139] The MEUs concluded on this point by saying:

> Given the foregoing, and consistent with the Closing Submissions of the Industrial Group and Dalhousie at pages 3-4, the MEUs believe that the $70 million reduction in revenue requirement as compared to NS Power's original filing can be achieved. In the next GRA, it will be important for the Board and all parties to carefully review and compare NS Power's actual financial performance in 2022, 2023, and 2024 with the forecasts originally filed in this GRA proceeding to fully understand the areas where and how cost savings were achieved, in order to identify all opportunities to keep the non-fuel costs in NS Power's rates as low as reasonably possible on behalf of ratepayers for 2025 and beyond, as the Province sought to do with the PUA Amendments.
>
> [MEUs Reply Submissions, pp. 7-8]

[140] In its Closing Submission, the NRR argued that the GRA Settlement Agreement increased rates and contravened the "purpose, spirit and intent of Bill 212." It expressed concerns with several aspects of the GRA Settlement Agreement.

[141] In respect of fuel and purchased power costs, NRR noted that the Province has already reduced the impact of escalating fuel costs through forgiveness of GHG costs and was continuing to explore further ways to mitigate these costs. However, NRR argued that the extra fuel costs falling on ratepayers were largely due to the cost of having to replace undelivered Maritime Link energy in a high-cost period and NS Power's profits should "bear at least a portion of inflated fuel costs that are being passed along to consumers."

[142] In terms of NS Power's non-fuel costs, NRR said the proposed non-fuel rate increase did not properly account for DSM costs. Rather than allow for an increase to cover the full annual amounts of DSM costs approved by the Board (M10473), NRR submitted only the difference between DSM costs approved for 2022 and those approved for 2023 and 2024 should be recovered from ratepayers under the legislated rate cap.

7.3.2 Fuel Increase

[143] As noted above, NRR expressed concern about the cost of replacing undelivered Maritime Link energy and suggested that at least a portion of this should not be passed along to customers. It did not suggest what that portion should be or how it should be calculated.

[144] Evidence filed on behalf of the CA by Resource Insight raised a similar concern. It noted the NS Block of energy did not materialize as contemplated in the 2020-2022 Fuel Stability Plan and since the date of the Acceleration Agreement that triggered the commencement of the NS Block on August 15, 2021. Resource Insight recommended that the Board reduce the fuel adjustment by a specific amount determined from its calculations of the additional cost, net of holdbacks ordered by the Board. Alternatively, Resource Insight said the Board could defer this question to the 2020-2021 FAM audit, but it recommended a balance reduction in this proceeding subject to an adjustment in either direction in that audit.

[145] In its Rebuttal Evidence, NS Power submitted that its general rate application was not a prudency review of its historical fuel costs and that such matters should be deferred to a FAM audit. NS Power went on to say that the Board had already determined that there was no imprudence in NSP Maritime Link Incorporated's (NSPML) decision to proceed with the completion of the Maritime Link on the originally scheduled timeline and that the Maritime Link had been determined to be "used and useful" by the Board. NS Power said:

> The Maritime Link has and will continue to be a significant contributor to NS Power's ability to meet its decarbonization goals in a timely way which benefits customers. NS Power understands and shares customer frustrations around the delay in the delivery of the NS Block and energy from Muskrat Falls; however, NS Power had no control over the circumstances which gave rise to those delays.

> NS Power has sought to mitigate impacts associated with the delay in the timing of the delivery of NS Block. The Company will still receive the energy for which it contracted as part of the Maritime Link project. NS Power has negotiated an additional agreement (Acceleration Agreement) with Nalcor in August 2021 which secured delivery of the NS Block energy prior to the commissioning of the LIL. In the absence of the Acceleration Agreement, customers would not have the benefit of the NS Block energy obtained prior to the commissioning of the LIL. As such, rather than exposing them to delay risks and costs, customers have received benefits under the Acceleration Agreement since August 2021. Under the Acceleration Agreement and the terms of the Energy & Capacity Agreement, Nalcor is also incentivized to replace the shortfall of the NS Block energy as soon as possible.
>
> [Exhibit N-102, p. 156]

[146] The Maritime Link project was approved by the Board in 2013 [2013 NSUARB 154 and 2013 NSUARB 242]. The application for the approval of that project was presented to the Board under the *Maritime Link Act*, S.N.S. 2012, c. 9 and the *Maritime Link Cost Recovery Process Regulations*, N.S. Reg. 189/2012. Under this legislation, the Board was required to hold a hearing and approve the project if, on the evidence and submissions provided, the Board was satisfied the project represented the lowest long-term cost alternative for electricity for ratepayers in the province that was also consistent with obligations under the *Electricity Act* and any obligations governing the release of GHG and air pollutants under the *Environment Act*, the *Canadian Environmental Protection Act* (Canada) and any associated agreements. Subject to several terms and conditions, the Board concluded the application met those requirements based on the evidence presented in the hearing.

[147] In 2017, when NSPML applied for its first interim assessment to begin recovering costs from NS Power under the *Maritime Link Act*, the Board determined that the Maritime Link would be “used and useful” in accordance with regulatory principles [2017 NSUARB 149]. In its decision, the Board noted that no Intervenor had suggested that NSPML was imprudent in continuing construction of the Maritime Link in the face of Nalcor’s announced delay in completion of the Muskrat Falls Generating Station.

[148] In 2022, the Board approved NSPML's application for the Maritime Link final project costs [2022 NSUARB 18]. In that decision, the Board noted that the planning and development of the Maritime Link Project was a significant endeavour, which NSPML managed to complete without the substantial cost overruns and construction delays that plagued many other energy mega-projects across North America.

[149] The Board notes the delivery of renewable energy over the Maritime Link continues to be a component of the Province's renewable energy standards governing the amount of renewable electricity that NS Power must supply to its customers. The *Renewable Electricity Regulations* require NS Power to deliver "20% of the electricity generated by the Muskrat Falls Generating Station if the Muskrat Falls Generating Station and associated transmission infrastructure is completed and in normal operation and the UARB has approved an assessment against NSPI under the *Maritime Link Act* and its regulations" to meet the renewable electricity standard through to the 80% requirement in 2030 and beyond.

[150] However, since the first interim assessment approval in 2017, the delayed delivery of the NS Block has been an ongoing concern.

[151] At the risk of oversimplifying the complex contractual arrangements in place between Emera and Nalcor for the Muskrat Falls project and the Maritime Link, NS Power's customers are, in effect, paying for the delivery of the NS Block energy but not receiving the energy in the timeframe contemplated. As such, NS Power must generate or procure other energy to replace the missing NS Block energy. Ultimately, NS Power expects to receive the NS Block and those missed deliveries will be made up later and displace energy that would otherwise have been procured or generated at that time.

[152] To the extent that current customers are paying for NS Block energy that will be delivered later, this can create a timing mismatch between the cost that is being paid and the benefit that is being produced. This can create unfairness in the costs paid by customers in different time periods, giving rise to so-called “intergenerational equity” concerns. These concerns arise from the delayed delivery of the NS Block even if NS Power is made whole by future deliveries. The longer the period between the missed delivery and the make-up delivery, the greater these concerns. To address this in some way, the Board has required that a portion of the assessment NS Power is required to pay to NSPML be held back.

[153] In 2017, an annual $10 million holdback was established. This was based on a conservative estimate of the economic benefit of the Maritime Link to NS Power’s customers on an annual basis. In 2022, when final project costs were formally approved, a form of holdback was continued to provide some ongoing protection to ratepayers. Each month, beginning April 1, 2022, NS Power was required to hold back $2 million from the approved assessment to pay for the cost of replacement energy if at least 90% of the NS Block (including Supplemental Energy) was not delivered. That arrangement was continued by the Board in its approval of NSPML’s 2023 cost assessment [2022 NSUARB 191]; however, the Board has directed that a proceeding be initiated to determine the disposition of holdback funds from 2022 and the administration of the holdback, generally, on a prospective basis, including any potential increase of the holdback.

[154] Depreciation and the amortization of deferred financing charges for the Maritime Link were also initially limited, but commenced on June 1, 2020, to ensure timely payment of the Government of Canada guaranteed debt for the Maritime Link and that

there be no default under the provisions of the credit arrangements and the Federal loan guarantee.

[155] While these various mechanisms may, in some small way, ameliorate intergenerational equity concerns, the question remains whether the replacement energy NS Power will receive from Nalcor will have the same economic value as it would have if it had been delivered on time. In its decision approving the final project costs for the Maritime Link project, the Board observed that the risk of prudently administering the redeliveries of the NS Block energy under the Acceleration Agreement and the Energy and Capacity Agreement rested on NS Power. The Board said it considers that the FAM audit process is the appropriate forum to review the economic value received by ratepayers from transactions involving the re-delivery of the NS Block (including Supplemental Energy) and Nalcor Market-priced Energy. The Board continues to be of this view.

[156] The Board notes that FAM audits are an integral component of NS Power's fuel adjustment mechanism. The FAM Plan of Administration provides that an audit of NS Power's fuel and purchased power costs be undertaken every second year. These audits are comprehensive and conducted by a qualified independent firm retained by the Board that considers fuel and energy procurement, fuel management and generation production, including:

- fuel and purchased power costs;
- operational availability and capacity factors for the generation fleet;
- fuel handling, quality control, inventory management and performance monitoring;
- the dispatching of resources;

- the review of contracts for prudency and compliance with NS Power's Fuel Manual;
- the use of hedging;
- system sales;
- the review of internal and external audit reports on the procurement of fuel and purchased power; and
- the calculation of base fuel costs and FAM adjustments.

[157] An audit report is ultimately filed with the Board and considered in a public hearing during which interested parties have an opportunity to question the auditor's findings and recommendations and present the Board with additional information. The Board may disallow NS Power's fuel costs if they are determined to have been imprudently incurred.

[158] Given this existing process, the Board does not agree that the fuel costs in this proceeding should be reduced to account for the possibility of ongoing late deliveries in the test years or to address historical differences. This issue may be considered in future audits.

[159] If the recovery of fuel and purchased power costs under the GRA Settlement Agreement, and approved in this decision, require changes to NS Power's FAM Plan of Administration, NS Power is directed to file the updated plan with its compliance filing.

7.3.3 Non-Fuel Increase

[160] Under the GRA Settlement Agreement, the overall non-fuel rate increases are split between DSM and other non-fuel items as follows:

GRA Settlement Agreement Non-fuel Rate Increases		
	2023	**2024**
DSM	3.6%	0.3%
Other Non-fuel	1.8%	0%
Total Non-fuel	5.4%	0.3%

[Exhibit N-156, NSUARB IR-3, Attachment 1, p. 1]

[161] While the parties appear to agree that the *PUA* amendments restrict non-fuel rate increases in this application to 1.8% except for increases relating to fuel and DSM, they have different interpretations of the meaning of "an increase respecting demand side management approved by the Board" in s.64A(3)(b). A brief review of the history of NS Power's recovery of DSM costs is helpful in putting this disagreement in context.

[162] In 2009, NS Power requested a DSM Rider for 2010 and beyond. The Board approved a rider that was based on the DSM program costs for the year and a true-up mechanism to account for any difference between the amount billed under the rider and approved program costs [2009 NSUARB 116]. As a result, DSM costs were not included in NS Power's base rates but were instead recovered through a rider that was adjusted each year. This practice continued until 2015 when it was eliminated by s. 12 of the *Electricity Efficiency and Conservation Restructuring (2014) Act*, S.N.S. 2014, c. 5:

> **Approvals of no effect**
>
> **12** **(1)** Effective on and after January 1, 2015, any approval with respect to Demand Side Management Cost Recovery Charges or the Demand Side Management Cost Recovery Rider in Nova Scotia Power Incorporated's rates and tariffs approved by the Review Board in its order dated February 1, 2013, is of no force and effect.
>
> **(2)** For greater certainty, subsection (1) does not apply to electricity sold by Nova Scotia Power Incorporated before January 1, 2015.

[163] The Board notes that the Order dated February 1, 2013, referenced in subsection 12(1), is the Board's Order approving NS Power's rates in its last general rate application [*2013-2014 GRA* decision] (M04972). The recovery of DSM costs through the periodically adjusted rider instead of in its base rates (which could only be adjusted in a general rate application) and its subsequent elimination by legislation, is the reason for the Board's earlier observation in this decision that DSM costs were not included in the restated 2014 compliance filing amounts shown in Exhibit N-20, FOR-01, Attachment 1.

[164] The *Restructuring (2014) Act* also amended the *PUA* to add the electricity efficiency and conservation franchise provisions under which the current franchise holder, EfficiencyOne, continues to operate. Transitional provisions deemed an agreement between the franchise holder and NS Power to exist for the supply of DSM to the end of 2015. Section 79R(3) also stipulated that NS Power's costs under this deemed agreement must be recovered over an eight-year period beginning January 1, 2016.

[165] On October 7, 2015, the Board approved EfficiencyOne's DSM Plan for 2016-2018. In its Order, the Board directed NS Power to file a proposed accounting treatment and cost recovery for the DSM programs in 2015 and under the 2016 to 2018 plan (M06733).

[166] In a letter to the Board dated December 18, 2015, NS Power advised it intended to expense the 2016 amortization amount for the 2015 DSM program in its 2016 operating costs. It also advised that it was not applying for a general rate application for 2016 and believed it could absorb the associated 2015 and 2016 DSM program costs in the revenue generated from its existing rates. It said it had not yet determined whether it

could absorb DSM amounts for the years beyond 2016 and had not yet determined whether it would file a general rate application for 2017.

[167] In an IR from Board Counsel consultant, Multeese Consulting, in that proceeding (M07151), NS Power was asked about the amount of DSM costs in its current rates. NS Power responded:

> Response IR-6:
>
> NS Power does not consider its current non-fuel rates to contain DSM funds. Although there is currently no portion of the revenue requirement from the previous GRA that is collected explicitly to pay for DSM programming, NS Power has considered the sum of its forecasted expenses for 2016, including the 2016 DSM program costs, when making the determination that it would expense 2016 DSM costs and absorb the recovery risk of those costs. The Company will make a similar determination when considering whether to apply for a GRA for 2017-2019 as contemplated under the *Electricity Plan Implementation (2015) Act*. If the Company does not apply for a GRA, it has requested until June 30, 2016 to finalize its Cost Recovery proposal for post 2016 DSM costs.
>
> [M07151, Exhibit N-8]

[168] The Board's decision in the matter, dated April 11, 2016, denied NS Power's request to defer the determination of its accounting treatment and recovery of its 2017, 2018 and 2019 DSM expenditures. The Board reasoned that since NS Power had decided not to apply for a general rate application in 2016 (and was precluded from changing its general rates earlier than January 1, 2020, under the *Electricity Plan Implementation (2015) Act*, S.N.S. 2015, c.31, s.18), NS Power had decided to absorb 2017 to 2019 DSM costs within its existing rates. Additionally, the Board noted that funds relating to a fixed cost recovery amortization, the s.21 tax deferral and 2008/09 DSM amortization continued "to be collected in current rates even though they are no longer required for those purposes, and could be available to fund annual DSM costs."

[169] In its Closing Submissions in this proceeding, NRR referred to the Board's decision in M07151 and, noting that NS Power did not raise the issue again in subsequent

hearings on DSM costs, suggested this meant that NS Power accepted that "DSM costs were part of rates in those years." NRR went on to conclude:

> NRR submits that the DSM amount referenced in the Settlement Agreement is not in keeping with the *PUA*, and that only amounts *incremental* to the 2022 year, recently approved by the UARB in M10473, were what the Legislature intended to include in rates.
>
> [NRR Closing Submission, p. 15]

[170] NS Power's position on this issue was expressed in its response to NSPI (NSDNRR) IR-4 (GRA Settlement Agreement) [Exhibit N-157]. NS Power said the full Board-approved amount for DSM spending and the "incremental amount" were in fact the same for rate setting purposes for 2023 and 2024. In making this statement, NS Power noted that the rate rider that was in effect prior to 2015 was removed and that:

> … although the Company has been able to "absorb" the cost of DSM programming in Board-approved rates since the discontinuation of the DSM Rider in 2015, this was achieved through variances in revenue and cost forecasts from those underpinning 2014 rates. There is no direct linkage to the changes in cost and revenue amounts since 2014 to annual class DSM programing approved by the Board.
>
> [Exhibit N-157, IR-4, p. 2]

[171] NS Power's IR response went on to address the Board's earlier comments about the amounts included in rates in 2014 for the amortization of certain deferrals that were no longer needed for those purposes being available to offset DSM costs after the removal of the earlier DSM rider. NS Power stated:

> This consideration reinforces why it is the full forecast cost of DSM programs which must be included in the proposed rate increases as provided through the Settlement Agreement, and not a lesser amount. In its application the Company has appropriately removed past costs from its revenue requirement, such as the Section 21 tax amortization referenced in the Board Decision.
>
> Effectively, for a reduced incremental approach to DSM spending to be considered the Company would also need to reinstate costs from the prior GRAs, even though these costs are no longer borne by the Company. Such an approach is illogical and inconsistent with well-established regulatory practice in Nova Scotia for the setting of the utility's revenue requirement and determination of required rate increases and, as such, is not being proposed by the Company.

> What is being proposed are rate increases which provide for the full recovery of DSM program costs through a DSM Rider beginning in 2023, as was the case prior to 2015. This recognizes that these are Board-approved expenditures (M10473), which are not controlled or managed by NS Power, and are in no part included in the Company's general rates.
>
> [Exhibit N-157, IR-4, p. 3]

[172] The Board accepts that DSM costs were not included in the revenue requirement used to set NS Power's base rates (or general rates as NS Power referred to them in the passage above) in its 2013-2014 GRA. The revenue needed to recover DSM costs was recovered through a separate DSM Rider that was subsequently eliminated by legislation. The Board also accepts that, since the DSM Rider was eliminated in 2015, NS Power has paid for DSM costs with revenue collected from its customers through its general rates.

[173] Whether the rate increase above the 1.8% rate cap that may be allowed "respecting demand side management approved by the Board" is to be determined relative to the amount included in base (or general) rates in 2014 (none) or actual DSM costs immediately before the passage of Bill 212 ($39 million approved in matter M09096) is a question of statutory interpretation. The Board estimates that this difference in interpretation accounts for approximately 2.7% of the proposed 6.9% increase in 2023 and does not contribute at all to the proposed 6.9% increase in 2024. That increase only includes the additional $4.4 million in approved DSM spending (M10473) between 2023 ($53.1 million) and 2024 ($57.5 million) in the proposed non-fuel increase in that year.

[174] Notwithstanding the well-recognized statutory interpretation framework discussed previously, none of the parties in this proceeding presented the Board with a robust statutory interpretation analysis. NS Power and NRR did little more than refer to the factual circumstances relating to the recovery of DSM costs by NS Power and state

their positions on what the legislation allowed or intended. For the most part, the other parties in the proceeding did not explicitly address this issue.

[175] While submitting that NS Power's position was a reasonable interpretation of the legislation, the CA left the matter for the Board's determination:

> The DSM Rider represents a portion (approximately 3.5%) of the proposed rate increase. In its reply to NSDNRR IR-4 (N-157), NS Power provided its view of how inclusion of the full DSM amount is consistent with legislation. It will be for the Board to decide whether the proposed settlement complies with legislative provisions. From the perspective of the Consumer Advocate, the position expressed by NS Power represents a reasonable interpretation, based on all surrounding circumstances.
>
> [CA Closing Submission, p. 5]

[176] The Closing Submission filed by the Industrial Group and Dalhousie University similarly noted that "the Board will have to determine as a matter of statutory interpretation what was intended by the words 'increase respecting DSM'" noting that "Bill 212 is not a model of legislative clarity on this."

[177] The Board must, therefore, embark on its own analysis of the meaning of s. 64A(3) of the *PUA*, considering the text, context and purpose as discussed in *Vavilov*.

Text

[178] This analysis begins with the text of the provision:

> **64A (3)** For the purpose of Board Case Number M10431, the net rate increase for the utility, across all rate classes, in 2022, 2023 and 2024 must not be greater than one and eight-tenths per cent, with the exception of an increase respecting
>
> (a) fuel and purchased power; and
>
> (b) demand-side management approved by the Board.

[179] Reading through the provision, the Board notes that the word "utility" is defined in s. 64A(1) to mean "Nova Scotia Power Incorporated" and the application of the provision is limited to the current Board proceeding (M10431). The direction that is

provided is that “the net rate increase for the utility, across all rate classes, in 2022, 2023 and 2024 must not be greater than one and eight-tenths per cent.” The Board understands this to mean that it is not authorized to approve an overall average rate increase which results in more than a 1.8% increase in the overall average rates presently paid by ratepayers currently to the end of 2024 (aside from the exceptions considered in the following paragraphs of this decision). Because of differences in rate class cost-allocation and rate design, changes in rates in some rate classes may be more or less than the 1.8% cap, but the overall average (across all rate classes) must not be more than 1.8%.

[180] If there is any disagreement about whether the permitted 1.8% rate increase may occur in one year or must be spread evenly over the test years, there is no basis for it in the text of the provision. The text includes no restrictions on when the 1.8% increase might occur, beyond the requirement that the net increase in 2022, 2023 and 2024 be not more than 1.8%.

[181] The major dispute arises with the introduction of exceptions to the 1.8% rate increase cap for “fuel and purchased power” and “demand side management approved by the Board.” Increases “respecting” these matters may cause the net rate increase for the Utility to be more than 1.8%.

[182] The use of the word “respecting” suggests that the increase that is referenced is the previously mentioned “net rate increase” and not an increase in the cost of the excluded items specifically. Had the latter been intended, the use of the word “in” rather than “respecting” would have more clearly focused the question on an increase in approved costs for DSM.

[183] As discussed earlier, while rates and costs are related under cost of service rate regulation, they are not the same. A utility's costs are used to determine its revenue requirement, which is the amount of revenue the utility requires and that rates will be designed and set to recover. But once rates are set, actual costs will vary between rate cases, whereas rates will not. Rates remain the same until the next general rate application when the utility's costs will again be reviewed and used to determine a new revenue requirement to set new rates. Furthermore, rate changes may occur in a general rate application due to changes in demand, even if costs stay the same.

[184] The focus of the provision on rate increases rather than cost increases favours NS Power's interpretation of the provision but the words used are not "precise and unequivocal." Even if they appeared to be so, the words of a provision might be read differently in the fuller context of the legislation and when the legislative purpose is considered.

Context

[185] Considering the entirety of s. 64A, the Board observes that subsection (3) is included with other subsections that restrict NS Power's ability to seek rate increases or fully recover its costs. Some of these provisions were specific to earlier proceedings and time periods and have no current application. Subsections (2A) and (2C) fall into this category.

[186] Subsection 64A(2) restricts the Board's ability to grant a general rate increase sooner than 24 months after the effective date of the last increase; however,

64A(2B) confirms the Board's authority to order a staged or multi-year general rate increase.

[187] Subsection 64A(3A) was added by the *PUA* amendments along with s. 64A(3). It relates specifically to subsection (3) and directs that any net rate increase up to 1.8% must be kept separate from other funds of the utility and may only be used to improve the reliability of service to ratepayers (excluding increases respecting fuel and purchased power and demand side management approved by the Board).

[188] Subsections 64A(4)–(6) also refer specifically to s. 64A(3). Although the Board's starting assumption must be that the legislation is presumed to be accurate and well drafted, in this case the Board is forced to conclude that these subsections were either retained in error or that the Legislature made a mistake in fully repealing and replacing s.64A(3). Before Bill 212, s. 64A(3) read:

> **64A (3)** Subsection (2) does not apply if the Board determines that exceptional circumstances exist that have caused or will cause substantial financial harm to the ratepayers of the utility or to the utility.

[189] As mentioned previously, s. 64A(2) restricts the granting of a general rate increase to no sooner than 24 months after the last general rate increase. Before Bill 212, the Board could grant a general rate increase sooner if there were exceptional circumstances and if these circumstances had or would cause substantial harm to ratepayers or the utility. Subsections 64A(4) to (6) related to the authority of the Board to act in exceptional circumstances and required the Board to hold a hearing before determining whether exceptional circumstances existed and to hold a separate hearing on general rates only after it had determined that to be the case. As the Board's ability to act in exceptional circumstances appears to have been removed by Bill 212, the Board

cannot interpret subsections 64A(4) – (6) as having ongoing meaning and has ignored them in its contextual analysis of s. 64A(3).

[190] In the context of the surrounding sections of the *PUA*, the provision in question follows s. 64, which addresses a public utility's duty to obtain Board approval for its rates, tolls and charges. In different ways, s. 64A limits or qualifies the Utility's ability to seek rates or the Board's ability to approve them. It is followed by other provisions added by Bill 212 dealing with the return on equity in this proceeding and, beyond this proceeding, the payment of interest and the duty to return excess earnings to ratepayers.

[191] The provisions added by Bill 212 also target non-fuel costs, with a particular but not exclusive focus on NS Power's cost of capital and an exclusion for DSM costs. These Bill 212 amendments are grouped around a pre-existing limitation on the recovery of executive compensation.

[192] Collectively, these provisions appear to act as limits or exceptions to the general provisions in the *PUA* governing a utility's entitlement to the recovery of its costs through rates set by the Board. In particular, the recovery of proper allowances for depreciation in s. 41 and a just and reasonable return on rate base, reasonable and prudent expenses and all just allowances under s. 45. These other provisions in the *PUA* do not specifically address the interpretive differences over s. 64A(3) arising in this proceeding, but they do frame that provision as a limitation or qualification on the underlying right of a utility to recover its expenses based on the cost of service methodology that is the foundation of the *PUA*.

Purpose

[193] There are no explicit purpose provisions in the *PUA*. As discussed previously, the *Contracts Case* considered there were two great objectives enshrined in the *PUA* and almost all provisions in the statute are directed towards securing these two objectives:

(1) All rates charged must be just, reasonable and sufficient and not discriminatory or preferential.

(2) Service must be adequately, efficiently and reasonably supplied to the public.

[194] Regarding rates, the Appeal Division said they must be reasonable and just for the public served and sufficient for the utility. The rates must be sufficient to provide the utility with the opportunity to earn a just and reasonable return after allowing for operating expenses and other just allowances – no less and no more.

[195] The *Contracts Case* was decided in 1976. As just considered, s. 64A to 64C affect or qualify this general objective. These provisions were all added since 2006, 30 years after the *Contracts Case* and more than a decade after NS Power was privatized. Some of them, like s. 64A(3), were just introduced by Bill 212.

[196] Bill 212 also has no explicit purpose provision. NRR addressed the intent of the *PUA* amendments in its Closing Submission. It said that the 1.8% rate increase cap, which applied except for increases relating to fuel and purchased power and demand side management as approved by the Board, was a “reasonable and necessary step to reduce the inflationary burden facing Nova Scotians in the near-term.”

[197] NRR also said:

> 43. Bill 212 was introduced to protect ratepayers from significant shock based on unprecedented global inflationary pressures, as confirmed in the Premier's letter to the Board dated November 28, 2022. The terms of the Settlement Agreement increase rates and contravene the purpose, spirit, and intent of Bill 212.
>
> 44. Prior to the GRA proceeding, NSP returned a minimum of $125 million in profits each year for the last 12 years. These profits benefit NSP's shareholders but offer no direct benefit to ratepayers. NSP's original position in the GRA proceeding, if granted, would have further inflated these profits.
>
> 45. During harsh economic times, it is unreasonable to impose further hardship on ratepayers to enhance corporate returns. Corporate social responsibility calls for a sharing of the burden to maximize relief for ratepayers for the cost of an essential service.
>
> [NRR Closing Submission, p. 9]

[198] More directly, the Premier's letter stated: "The entire purpose of Bill 212 was to protect Nova Scotians."

[199] For the most part, the submissions the Board received from the other parties did not explicitly address the purpose of Bill 212. In the Reply Submission filed by the MEUs, they described what "the Province sought to do with the *PUA* amendments" as keeping the non-fuel costs in NS Power's rates as low as reasonably possible on behalf of ratepayers and providing options to contain NS Power's costs given the current affordability crisis facing Nova Scotians.

[200] The Board accepts that the Legislature passed Bill 212 with ratepayer protection in mind. However, s. 64A does not freeze rates. Furthermore, by explicitly excluding rate increases respecting fuel and purchased power, which by the time Bill 212 was introduced were clearly putting the most upward pressure on NS Power's rates, it does not prohibit large rate increases in this proceeding either. Instead, the protection appears to be aimed at a subset of NS Power's costs – non-fuel costs – with several

provisions aimed more specifically at NS Power's cost of capital (ss. 30(5), 64AA, 64AB and 64C).

[201] In terms of the exemption for DSM costs, the Board notes that while these are non-fuel costs, they are costs that are collected by NS Power to fund programs administered by EfficiencyOne. Under s. 79I of the *PUA*, NS Power must undertake cost-effective DSM by entering into a Board approved DSM purchase agreement with the DSM franchise holder that includes the amount that NS Power must pay the franchise holder to supply DSM.

[202] Section 79M(5) of the *PUA* directs the Board to provide for NS Power's recovery of costs it incurs under an approved DSM purchase agreement:

> **79M** (5) In making an order approving an agreement pursuant to Section 79L, the Board shall include a provision to permit Nova Scotia Power Incorporated to recover any costs Nova Scotia Power Incorporated incurs pursuant to the approved agreement, including through its rate base, pursuant to Section 45, in the year in which the costs are incurred or as deferred by the Board.

[203] The recovery of costs for DSM programs by NS Power is not for the purpose of directly funding its operations, although they are intended to provide ratepayer and system benefits. The funds are for the DSM franchise holders and the funding levels are specifically approved by the Board. The amount of spending is not in NS Power's control. Given the foregoing, DSM costs are different in nature from NS Power's other non-fuel costs which may be more prone to over-estimation, over-recovery and to lead to excess earnings.

[204] In summary, the Board must interpret the words of the legislation in their entire context and in their grammatical and ordinary sense harmoniously with the scheme of the *Act*, the object of the *Act*, and the intention of the Legislature.

[205] As discussed in the *Contracts Case*, one of the foundational principles underpinning the *PUA* is the “justness of rates,” which requires that rates must be sufficient to allow for the recovery of operating expenses and a “just and reasonable” return. Bill 212 affects the Board’s ability to set rates based on these principles in this proceeding.

[206] The Legislature enacted the *PUA* amendments to protect ratepayers. Although s. 64A(3) can be viewed as establishing a form of rate cap, it did not preclude increases in rates. Given the exclusion of fuel and purchased power costs when these were expected to cause significant upward pressure on rates, it also did not preclude large increases in rates. Instead, the protection afforded by the *PUA* amendments appears to be focused on NS Power’s non-fuel costs, with several amendments targeting NS Power’s cost of capital and earnings.

[207] NS Power and NRR disagree about the interpretation of s. 64A(3)(b). NS Power submitted that the permitted rate increase respecting demand side management approved by the Board is to be determined based on the amount of DSM costs included in the revenue requirement used when rates were last set in the *2013-2014 GRA* decision (which was nothing). NRR submitted that the permitted rate increase respecting DSM may only include the incremental increase in costs between approved DSM spending in 2022 and the test years. Reading s. 64A(3) harmoniously with the scheme of the *Act*, the object of the *Act* and the intention of the Legislature, the Board finds that NS Power’s interpretation is more compelling (and by extension that of the parties to the GRA Settlement Agreement who urged the Board to accept it).

[208] The text of s. 64A(3) addresses rate increases. Although NS Power has clearly used revenue collected from ratepayers to pay for DSM costs since its last rate case, the base (or general) rates set at that time did not include DSM costs. As such, all of NS Power's DSM costs in its revenue requirement for 2023 would be incremental to the revenue requirement used to set 2014 rates (NS Power's current rates).

[209] This interpretation best respects the underlying principles of the *PUA* as expressed in the *Contracts Case* and the specific requirement in s. 79M(5) permitting NS Power to recover DSM costs. At the same time, it does not defeat the objective of Bill 212. Although Bill 212 is intended to protect ratepayers, the exclusion of fuel costs, which were exerting the most pressure on rates, suggests the intent was to limit a type of cost rather than to limit potentially large increases.

[210] The focus of Bill 212 is on non-fuel costs, especially, although not exclusively, those affecting NS Power's cost of capital and earnings. The exclusion of DSM costs is consistent with this, since although they are collected by NS Power, they are provided to EfficiencyOne to fund its Board-approved programs. As such, these revenues are less likely to contribute to NS Power's earnings, particularly given ratepayer requests to true-up these costs since 2015. With the approval of the DSM Rider sought by NS Power in this proceeding, which is generally supported by NRR, that possibility is virtually eliminated.

[211] Based on the interpretation of s. 64A(3) of the *PUA* on which the rates under the GRA Settlement Agreement are proposed, ratepayers receive meaningful benefits consistent with the types of costs targeted by Bill 212. Rate increases in respect of non-fuel items are nearly half of what they were proposed to be before Bill 212. Much of this

is achieved through reductions in NS Power's earnings, compared to what it had originally requested.

7.3.4 Findings

[212] The *PUA* requires the Board to set fair rates for utilities. As discussed in the *Contracts Case* considered earlier in this decision, that means rates that are fair as between the utility and its customers, and as between the utility's various customer classes. Fair rates as between the utility and its customers are rates that provide the utility with an opportunity to earn a just and reasonable return after providing for the recovery of reasonable and prudent operating costs and other just allowances. The fair return requirement is discussed in more detail later in this decision.

[213] The Board is satisfied on the evidence in this proceeding that the proposed rates under the GRA Settlement Agreement are appropriate. The Board finds that the proposal is within what is permitted under the *PUA* (including Bill 212). The Board is also satisfied that NS Power's reasonable and prudent costs will be at least as much as the effective revenue requirement needed to support the proposed rates.

[214] While NS Power has noted that the "non-fuel, non-DSM cap" imposed by Bill 212 will reduce its forecast revenue increase by $70 million over 2023 and 2024, the Board agrees with the submissions filed by the Industrial Group and Dalhousie University, and by the MEUs, that cost reductions can be achieved, and that they must be achieved without sacrificing reliability.

[215] While the Board has concluded that NS Power's reasonable and prudent costs support the increases under the GRA Settlement Agreement, it is rarely the case

that rate increases are welcomed by customers. In this case, the back-to-back 6.9% increases in 2023 and 2024 are concerning, particularly in a period of higher inflation.

[216] For many, electricity rates are already unaffordable. This was certainly the sentiment expressed by many Nova Scotians who took the time to prepare and send letters of comment to the Board about this application. This concern was also aptly stated in the Affordable Energy Coalition's Opening Statement and Closing Submissions:

> Nova Scotia has one of the highest rates of energy poverty in the country due to our lower incomes and higher energy costs arising from our reliance on oil and coal. Energy services are necessities – for food preparation, winter warmth and as the planet heats up, for summer cooling. Access to energy is a human rights issue. Access is often threatened due to low incomes. Many families struggle with the "heat or eat" challenge especially in this period of high fossil fuel prices.
>
> [Exhibit N-105, Opening Statement, p. 2 and Closing Submissions, p. 2]

[217] As noted by the Nova Scotia Court of Appeal in *Dalhousie Legal Aid Service*, the Board's regulatory power under the *PUA* is not an instrument of social policy. The Board cannot, as noted by the Federal Court of Appeal in *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, simply disallow NS Power's reasonable costs to make rates more affordable (discussed in more detail later in this decision). While the Board can disallow costs found to be imprudent or unreasonable (and has), absent such a finding, NS Power's costs must be reflected in the rates paid by customers.

[218] That said, there are regulatory tools available to the Board to mitigate the impact of rate increases. For example, the Board may defer the recovery of costs to a later period, or it may direct the creation of a regulatory asset to be amortized over an extended period rather than be recovered all at once. This is the premise underpinning the proposed Decarbonization Deferral Account in this proceeding. It would be a means of managing the significant costs expected to be incurred by electricity ratepayers to

transition away from coal-fired electricity generation and have 80% of electricity in the province supplied by renewable energy by 2030 and towards the Province's net-zero GHG emissions target by 2050.

[219] There are trades-offs involved with using these tools. Requiring future ratepayers to pay the costs of current customers can create concerns about intergenerational equity. Additionally, the delayed recovery of legitimate costs generally attracts interest or similar carrying costs, which increases the overall amount paid by ratepayers. This was the essence of NRR's comments in its Closing Submissions where it said, "Deferrals can mitigate rate shock to consumers in the short term, but over time the total amount payable is increased because of interest chargeable to ratepayers for financing the deferral."

[220] In this regard, the Board observes that the anticipated fuel costs in 2023 and 2024 (as well as unrecovered fuel costs to the end of 2022) are already partially excluded from the base fuel costs for 2023 and 2024 under the GRA Settlement Agreement. If these costs are incurred as forecast, the result is essentially a deferral of a significant amount of fuel costs. These costs are proposed to be included in FAM Riders in 2024 and 2025, although "as the rate increase required to collect under-recovered fuel amounts in a 2024 FAM Rider is material for all or certain of the customer classes, the parties will work in a good faith manner to defer a portion of the impact of the increase and costs to 2025 or an additional period as may be reasonable and appropriate."

[221] In the GRA Settlement Agreement, a balance was struck between NS Power and representatives of all its customer classes. It included the Affordable Energy

Coalition, which works on behalf of low- and modest-income Nova Scotians across the province. It also included the Ecology Action Centre.

[222] Given the broad acceptance by customer representatives and these other parties, and the looming cost pressures likely to arise through the energy transition, the Board finds the proposed rate increases in the GRA Settlement Agreement to be just and it would not be appropriate in this case to defer even more fuel costs for additional and temporary rate relief in the test years. In addition to the intergenerational equity and higher cost concerns noted above, this runs the very real risk of compounding rate pressures from the energy transition in the future and reducing the flexibility that may be available to manage those costs in a reasonable timeframe.

[223] Finally, the Board notes that it has received many comments from the public about NS Power's requested rate increase in the face of concerns about reliability. In its *NS Power 2005 GRA* decision, the Board stated:

> 16 …the Board has received a number of comments from members of the public questioning, among other things, why NSPI's request for a rate increase should be considered when the service provided by NSPI is, in the view of these customers, inadequate and unsatisfactory.
>
> 17 While the Board recognizes the logic of this reaction, it is important to understand why this form of sanction cannot reasonably be applied to a regulated utility. NSPI is not like an unregulated retailer. It is a virtual monopoly which operates its business on a cost-of-service basis. Providing electricity to all communities in the Province was not (and likely still is not) financially feasible for private, competitive companies. For that reason, the Province's electric service supplier is a cost-of service monopoly. In return for undertaking and continuing the costs of electrification of the Province, the Utility is permitted, under the Act, to recover the reasonable and prudent costs of providing this service. Because it is a monopoly, regulation operates as a surrogate for competition. One of the regulator's tasks is to balance the need for the Utility to recover its reasonable and prudent costs with the need to ensure that ratepayers are charged fair and reasonable rates.
>
> 18 It is in the interests of all Nova Scotians to ensure that NSPI continues to be a stable and financially sound company. This is a reality which the Board must consider when determining what, if any, rate increase is warranted.
>
> 19 In short, rates charged to customers are based on costs incurred by the Utility in providing service. If the Board finds certain costs to be imprudent or unreasonable, it can (and has) disallowed such expenditures and reduced proposed rate increases accordingly. The Board cannot, however, make rate decisions based solely on reliability issues or

> current public opinion of the Utility. There are appropriate sanctions a regulator can impose should a Utility be found to have an inadequate or unreliable system. In many cases, it is likely such sanctions would involve higher expenditures, rather than reductions in costs. However, the practical reality in a regulated utility environment is that sanctions for service-related issues generally do not include a moratorium on rate increases.
>
> [2005 NSUARB 27]

The Board continues to be of this view.

7.4 Cost of Capital and Earnings Sharing

[224] NS Power's current rates are set on a return on equity (ROE) of 9% and a capital structure consisting of 37.5% equity. The Utility's actual annual returns may produce an ROE as high as 9.25% with equity forming as much as 40% of its capital structure. NS Power must return earnings above these thresholds to its customers.

[225] The Utility's obligation to return earnings above its approved limits was first established under a settlement agreement in 2007. Since that time, excess earnings have benefited ratepayers through various mechanisms. When the Section 21 tax deferral existed, excess earnings were used to reduce that deferral. In recent years, excess earnings were applied directly to balances owing by ratepayers through the FAM. In its decision on NS Power's 2020-2022 Fuel Stability Plan [2019 NSUARB 165], the Board confirmed its jurisdiction to determine the disposition of excess earnings, regardless of whether NS Power agreed to it in a settlement with other parties.

[226] In this proceeding, NS Power proposed to continue to set rates based on a 9% ROE, but to permit actual returns within a range up to 9.5%. NS Power also requested that the Board approve changes to its debt-to-equity ratio, for rate setting purposes, starting in 2022 at 61.2%/38.8% and then increasing the equity component to 41.3% in 2023, followed by an increase to 43.8% in 2024. Additionally, NS Power asked for

permission to earn on a common equity thickness of up to 45% in each year between 2022 and 2024. NS Power proposed that any surplus earnings above these thresholds be shared equally by NS Power and its customers.

7.4.1 The Fair Return Requirement and Standard

[227] NS Power has a natural monopoly as there is limited competition and the forces of supply and demand in the electricity market are absent in Nova Scotia. Part of regulating NS Power includes determining the rate of return that is used in setting customers' rates. As discussed earlier, s. 45 of the *PUA* entitles a utility to earn a just and reasonable return on its rate base, in addition to the recovery of its operating expenses and other just allowances.

[228] A fair return on rate base is important for the sustainability of NS Power's service. A low return on rate base may discourage investment in the Utility. It may also lead to a poor credit rating, which will cause financial institutions to increase the rate of interest on loans used by the Utility to provide service. This may result in the Utility's rates increasing just to cover additional borrowing costs. It may even cause it to be excluded from participating in some debt markets altogether.

[229] There is a well-recognized and long-standing legal standard the Board must follow when approving a utility's return on its investment. Nearly a century ago, the Supreme Court of Canada described the test as follows:

> 18 The duty of the 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. <u>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.</u> In fixing this net return the Board should take into

> consideration the rate of interest which the company is obliged to pay upon its bonds as a result of having to sell them at a time when the rate of interest payable thereon exceeded that payable on bonds issued at the time of the hearing. To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in order to fix a proper return in 1927, was whether or not the conditions of the money market had altered, and, if so, in what direction, and to what extent. [Emphasis added]
>
> [*Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186]

[230] This test was more recently accepted by the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44:

> 15 This Court has had the occasion to consider the meaning of similar statutory language in *Edmonton (City) v. Northwestern Utilities Ltd.*, [1929] S.C.R. 186 (S.C.C.). In that case, the Court held that "fair and reasonable" rates were those "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" (pp. 192-93).
>
> 16 This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers: *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 (F.C.A.).

[231] The latter part of this passage endorsed the Federal Court of Appeal's comments in *TransCanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, where that court said:

> 12 Even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the Board does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.
>
> 13 <u>In the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain existing ones. Eventually, it will go out of business. This will harm not only its shareholders, but also the customers it will no longer be able to service.</u> The impact on customers and ultimately consumers will be even more significant where there is insufficient competition in the market to provide adequate alternative service. [Emphasis added]

[232] The Federal Court of Appeal went on to address a concern raised by TransCanada Pipelines that the National Energy Board set its return on equity too low because it improperly considered the impact that higher rates would have on its customers. Although the court found the evidence did not support the conclusion that the National Energy Board had suppressed the return on equity because of the resulting impact on customers, it accepted this consideration was not a relevant factor under the *Northwestern Utilities* test:

> 35 In oral argument, the appellant conceded that it does not object to its customers having input into the Board's cost determinations and in particular, its cost of capital determination, provided the issues in dispute are restricted to the costs of the Mainline. However, the appellant does object to the Board taking the impact of tolls on customers and consumers into account in determining the Mainline's cost of equity capital. The appellant says that the required rate of return on equity must be determined solely on the basis of the Mainline's cost of equity capital. The impact of any resulting toll increases on customers or consumers is an irrelevant consideration in that determination. The appellant does concede that when the final tolls are being fixed, the impact on the customers and consumers may be relevant, but insists that it is irrelevant when determining the required return on equity.
>
> 36 I think that this argument is sound and in keeping with the decision of the Supreme Court in *Northwestern Utilities*. The cost of equity capital does not change because allowing the Mainline to recover it would cause an increase in tolls. Under the Board's Equity Risk Premium methodology, the cost of equity capital is driven by the Board's estimate of the risk-free interest rate and the degree of risk investors perceive in the "benchmark" pipeline. The higher the risk, the higher their required rate of return. The degree of risk specific to the Mainline is accounted for by adjustments to its deemed capital structure. Accordingly, the cost to the Mainline of providing that rate of return on the equity component of its deemed capital structure is unaffected by the impact of tolls on customers or consumers.

[233] The Board notes the Federal Court of Appeal went on to say that although the impact on customers cannot be a factor in determining the utility's entitlement to a specific return on equity, any resulting increase in tolls may be a factor in determining the way the utility may be able to recover its costs. In particular, the court said if an increase would be so significant it would lead to "rate shock" if implemented all at once, rate increases could be phased in over time, "provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls

would have to compensate the utility for deferring recovery of its cost of capital" (para. 43).

[234] Similar principles are considered by utility regulators in the United States: *Bluefield Waterworks & Improvements Co. v. Public Service Commission of West Virginia* (1923), 262 U.S. 679 (U.S. W. Va.) and *Federal Power Commission v. Hope Natural Gas Co.* (1944), 320 U.S. 591 (U.S. Sup. Ct.).

[235] In *Energy Law and Policy* (Kaiser and Heggie, ed., 2011), Canadian authors, Gordon Kaiser and Bob Heggie, summarized the principles that have been considered by regulators to set fair returns:

> While no legislative guidance is provided as to what a regulator is to take into account in determining a fair return, United States and Canadian courts have considered the issue. The courts have listed factors that tribunals should consider, but have not prescribed methods for calculating a fair return. To be considered fair, tribunals have taken the following principles or standards into account in determining returns:
>
> - The return must be comparable to the return available in the market on an investment of similar risk: the comparable investment or earning principle.
> - The return must be sufficient to attract new utility capital investment: the capital attraction principle.
> - The return must be sufficient to maintain the financial integrity of the utility: the financial integrity principle.
>
> The comparable investment principle is based on the idea that in order to be fair to a utility equity investor, the investor must be satisfied that the potential return on the investment is sufficient to compensate for the risk assumed in relation to the entire spectrum of comparable competitive investments available. The challenge with this principle is finding comparable companies with similar risks.
>
> The financial integrity and capital attraction principles are more straightforward and generally will be satisfied if the comparable investment principle is met. Financial integrity is satisfied if the combined effect of the allowed return and the equity thickness of a utility's capital structure results in a debt coverage ratio sufficient to support stable investment grade ratings.
>
> Debt investors need earnings to provide security for the debt capital invested. The difficulty with this principle is determining whether a particular desired rating should drive the allowed return.

> Capital attraction means that returns must be adequate to attract necessary capital on reasonable terms to build required utility infrastructure.
>
> [*Energy Law and Policy*, pp. 188-189]

[236] *Northwestern Utilities*, *Bluefield* and *Hope* were recently referenced by the Board as the "landmark decisions which set out general principles with respect to rate of return" in *Re Nova Scotia Power Inc.*, [2019 NSUARB 165, para. 119].

[237] The assessment of these principles in any case before the Board is based on the evidence presented. In the current case, the Board was presented with expert evidence by several parties.

7.4.2 Overview of Cost of Capital Evidence

[238] NS Power presented evidence from its cost of capital expert witness James Coyne, of Concentric Energy Advisors, who used a combination of Discounted Cash Flow (DCF) models, the Capital Asset Pricing model (CAPM) and an Alternative Risk Premium model. Mr. Coyne estimated a ROE for NS Power of 10.1% based on the average of his model analysis. However, NS Power did not seek to increase its ROE for rate setting purposes from 9.0 %.

[239] Mr. Coyne suggested that increasing NS Power's common equity ratio from 37.5% to 45% is justified as NS Power faces greater financial and business risk. This assessment of greater financial risk is based on his comparison of common equity ratios of other utilities, finding NS Power's to be lower than the 40.4% average of Canadian utilities. He also compared NS Power's credit metrics to groups of selected comparator utilities and concluded that NS Power's credit metrics are weaker than comparable U.S. electric utilities. Mr. Coyne also deemed that NS Power faces considerable business risk

because of its ownership of thermal generation assets, weak economic conditions in Nova Scotia, weather and risk posed by regulation. He identified NS Power's obligation to decarbonize its electricity generation is fast approaching, which will require considerable investment. Mr. Coyne also suggested that NS Power has higher regulatory risk than other comparable utilities in his selected proxy groups due to the Fuel Adjustment Mechanism and the potential for expenditure requests to be denied.

[240] The cost of capital expert witness for Board Counsel, Dr. Laurence Booth recommended a 7.5% ROE based on his financial modeling using the CAPM and DCF models and his informed assessment of the market risk premium. He considers 7.5% reasonable for NS Power because it is no riskier than other electric distribution utilities in Canada which have a significantly lower average risk than U.S. utilities.

[241] Dr. Booth recommended that NS Power keep its common equity ratio at 37.5% as its business risk has not changed since the previous GRA. Rather, he considers that since 2012, NS Power improved its business risk assessment with S&P Global to "excellent" (before the introduction of Bill 212). In his evidence, Dr. Booth noted that NS Power has been able to earn its allowed ROE in most years since the previous GRA, which he sees as proof that it does not face long run risk. Further, Dr. Booth viewed money market conditions as positive, noting that after 2022, GDP growth is forecasted to be two percent with optimal employment levels. Regarding inflation, he suggested that the main forces of inflation in 2022 are the impact of COVID-19 and Russia's invasion of Ukraine, which have caused supply shortages and a significant increase in commodity prices. He cited forecasts by the Royal Bank of Canada in May and June 2022 and the

Bank of Canada itself expecting these inflationary factors to ease in 2022/23 and return to targeted levels.

[242] The CA's cost of capital expert witness, Dr. Randall Woolridge, noted that the current average authorized ROE for a Canadian utility is 8.83%, below the average authorized ROE in the U.S. of 9.38%. Based on his financial modeling using the CAPM, DCF and Risk Premium models, he recommended an ROE for NS Power of 8.75% with an earnings band of 8.5% to 9.0%. Dr. Woolridge acknowledged that this rate is slightly below the average for electric distribution companies, but that it reflects the low levels of interest rates and cost of capital.

[243] Dr. Woolridge recommended keeping NS Power's common equity ratio at 37.5%. He considered that NS Power's BBB+ credit rating with S&P Global was in keeping with other electric utilities and indicated that its risk is similar to other electric utilities (before the introduction of Bill 212). Additionally, Dr. Woolridge considered that NS Power demonstrated consistent financial performance under its current common equity ratio which earned it a strong credit rating. The Board notes that the S&P credit rating referenced by Dr. Woolridge was downgraded two notches since the passage of Bill 212.

[244] Dr. Woolridge noted that Mr. Coyne's model assumes higher interest rates and higher costs of accessing capital; however, he disagreed and considered that, from a historical perspective, interest rates and cost of capital in both Canada the U.S. are still low. In his view, utilities have taken advantage of the low interest rates of recent years. In his evidence he noted that starting in 2022, interest rates have increased in response to an improving economy and high levels of inflation. Although the central bank increased

interest rates, those increases reflect short-term lending rates, whereas long-term rates reflect expectations of economic growth and inflation. Dr. Woolridge cited U.S. investors' expected inflation using the inflation-protected Treasuries (TIPS) for the next five years at just above three percent, while the 10 and 30 year expected inflation rates are forecast below three percent. He noted that the current environment is reflective of a bond-market inversion, where short-term inflation expectations are higher than long-term inflation rate expectations. Dr. Woolridge concluded that interest rates and cost of capital are still at low levels while stock prices are high. Reported inflation is the primary economic concern; however, he viewed the outlook for the economy as positive in the long-term based on the TIPS expectations.

[245] Paul Chernick and John Wilson of Resource Insight, on behalf of the CA, made two recommendations about NS Power's requested change to its capital structure. First, they requested that the Board consider NS Power's refusal to communicate with the Board about delays and cost overruns on projects. Second, they asked that the Board consider NS Power's repeated capital cost overruns when setting the ROE.

[246] John Dalton of Power Advisory, NRR's expert witness, considered that NS Power's business risks were overstated by Mr. Coyne, citing the rating by S&P Global as "excellent" and its competitive position as "excellent", (note that these ratings have changed since the passage of Bill 212). Mr. Dalton suggested that Mr. Coyne did not account for the mitigating effects of the proposed DDA and the FAM on risk. He said NS Power's sales from residential and commercial customers are less affected by the business cycle, which mitigated commercial risk. Mr. Dalton noted that competition from

other fuel providers in the province is limited, insulating NS Power from competitive market forces.

[247] Mr. Dalton reasoned that Mr. Coyne misinterpreted Nova Scotia's economic position and demographic changes. Forecasts of economic growth in Nova Scotia from other sources are more favorable than the single source selected by Mr. Coyne. Mr. Dalton countered the weak demographic projections with recent population growth figures for 2021 from Statistics Canada.

[248] John Athas and Melissa Whitten of Daymark, on behalf of the SBA, recommended that NS Power should maintain its current ROE for rate setting purposes and its current range for actual earnings. They considered that applying the approved ROE to a higher equity thickness is equivalent to increasing the Utility's WACC by the difference in expected to actual equity thickness, and then providing the Utility with a bonus ROE.

[249] Daymark recommended that the Board deny NS Power's request to increase its common equity ratio to 45% and asked that it not be allowed to use an equity thickness higher than its actual equity thickness in any year. Daymark considered that investment in utilities is more attractive during periods of high inflation which reduces NS Power's investment risk. Further, NS Power's application did not suggest that it cannot access low-cost debt.

[250] Albert Dominie on behalf of the MEUs did not recommend a specific debt-to-equity ratio or ROE, but he asked that the Board consider the magnitude of the cost implications of NS Power's request to increase its common equity and thresholds for its ROE on customers over the long-term.

7.4.3 *Public Utilities Act* Amendments

[251] As discussed already, the recent amendments to the *PUA* affected the Board's discretion in this proceeding when setting NS Power's rate of return on equity and capital structure. Under s. 64AA, NS Power's return on equity must not be set at a rate greater than 9.25% and its equity ratio must not be greater than 40%. Under s. 64C, NS Power must return earnings above its approved range for return on equity to ratepayers. Although this continues the practice that has been in place for approximately 15 years, it is now mandatory under the legislation.

[252] Some Intervenors noted that the recent *PUA* amendments altered what they planned to ask the Board to set for the cost of capital for NS Power in this proceeding. As noted earlier in this decision, the Affordable Energy Coalition noted that they had argued in their Opening Statement that NS Power's profit level should be reduced but they signed the GRA Settlement Agreement "in view of the disruption created by Bill 212 and its effect on NSPI's financing." In their view, Bill 212 undermined the independent regulation of the electricity system and resulted in the downgrading of NS Power's credit rating and that this disruption "undermined our ability to argue for reduced profit levels at this time." It intends to pursue that issue in future proceedings.

[253] Counsel for the Industrial Group and Dalhousie University advised:

> The parties have agreed in the Settlement Agreement to an equity thickness of 40% and ROE of 9% for rate-setting, with an earnings band +/- 25 basis points. While our submissions had been drafted to argue for no change in NSPI's equity thickness and ROE, the basis for this draft argument was shaken in the wake of the PUA amendments and more recent bond and credit rating reports which speak to NSPI's current credit risk profile.
>
> It is challenging to know what weight should be placed upon these hearsay third-party reports and how they would be accounted for in standard utility risk assessment methodologies. Given the timing of the PUA amendments, none of the cost of capital experts has provided evidence on their impact to NSPI's risk premium. The assessment is complicated in light of the inter-relationship between NSPI and Emera.

> At present, Dalhousie University and the Industrial Group simply observe that the hearing evidence of a predictable and stable regulatory environment has been undermined. Approval of the Settlement Agreement offers some counter-balancing de-risking mechanisms: an increased equity thickness, agreement in principle on a DDA, a time-limited storm cost recovery rider, a DSM rider, continued pass-through of fuel costs and it leaves open the door for NSPI to apply for other cost deferrals. It is anticipated that DBRS Morningstar will be considering these and other matters before its next credit report is issued.
>
> [IG/Dalhousie Closing Submissions, p. 5]

[254] The CA commented specifically about the rate of return on equity:

> The Settlement Agreement seeks to set the return on equity at 9%. It is to be noted that both the Consumer Advocate and Board counsel consultant evidence supported a lower return on equity than 9%. Prior to the introduction of Bill 212 it had been the intention of the Consumer Advocate to seek a return on equity at less than 9%. That position was to be – in large measure – rooted in the opinions of Dr. Booth and Dr. Woolridge that the robust and independent rate setting process in Nova Scotia should lead to a lower return on equity. The passage of Bill 212 represented a post-hearing development that materially altered what reasonable position could be taken regarding the return on equity. In all those circumstances the Consumer Advocate submits that the Settlement Agreement ROE figure of 9% is reasonable.
>
> [CA Closing Submission, p. 4]

[255] The recent *PUA* amendments do raise serious questions about the continuing reliability of the opinions expressed by the cost of capital experts who presented the Board with evidence in this proceeding. As noted by Kaiser and Heggie, the comparable investment principle considers the return available in the market on an investment of similar risk.

[256] Bill 212 certainly had an impact on bond rating agency assessments of NS Power's risk. In response to information requests after filing the GRA Settlement Agreement with the Board, NS Power filed recent reports from DBRS Morningstar and S&P Global discussing this issue [Exhibits N-156 (IR-10) and N-159].

[257] In a report dated October 20, 2022, DBRS noted its "business risk assessment of NSPI will be negatively affected by the proposed amendment as the heightened and adverse political interference will reduce the predictability and stability of

the regulatory framework." On December 20, 2022, DBRS downgraded its "Issuer Rating and Unsecured Debentures & Medium-Term Notes rating [for NS Power] to BBB (high) from A (low) and its Commercial Paper rating to R-2 (high) from R-1 (low)."

[258] In a report dated October 24, 2022, S&P said it viewed the "amendment as negative for credit quality because it would likely weaken Emera Inc.'s financial measures and increase business risk, reflecting heightened regulatory risk." S&P went on to note:

> If the proposed legislation is passed, it would override Nova Scotia's robust regulatory process. Under our base case, we expect that utilities operate under a regulatory system that is sufficiently insulated from political intervention to efficiently protect the utility's credit risk profile even during stressful events. As such, Emera faces heightened regulatory risk in the province of Nova Scotia, supporting a potential reassessment of the regulatory framework in Nova Scotia, which could pressure credit quality.
>
> [Exhibit N-156, NSUARB IR-10, Attachment 2, p. 2]

[259] On November 21, 2022, S&P downgraded its long-term issuer credit rating on NS Power and its issuer-level rating on its senior unsecured debt by two notches to 'BBB-' from 'BBB+'. It also lowered its Canadian scale commercial paper rating on the company to 'A-3 (Cdn)' from 'A-1(Low)'. In doing so, S&P cited "political intervention that will materially undermine the NSUARB's regulatory construct and significantly increase NSPI's stand-alone business risk."

[260] As counsel for the Industrial Group and Dalhousie University highlighted, the legislation and bond rating agency reaction post-dated the filing of evidence by the cost of capital experts who appeared in the proceeding and the oral hearing, where the parties and the Board had an opportunity to question these experts about their opinions. It is possible, if not likely, that the passage of legislation like Bill 212 would have influenced the opinions about the risks faced by NS Power expressed by the experts in this proceeding. It is difficult to know the precise impact these events would have had on the expert opinions presented to the Board in this proceeding, but the events are fundamental

enough that the Board must question whether it can put any weight on the expert evidence it has received.

[261] Still, despite this difficulty, the Board must approve a cost of capital for NS Power in this application. The expert evidence filed in this proceeding conflicted. The approaches, assumptions and conclusions of each cost of capital expert were critiqued and challenged to such a degree that, in the Board's assessment, there is hardly any part of the cost of capital analysis that would not require the Board to make a finding in favour of one expert or another following a step-by-step review of their criticisms.

[262] Considering the Board's doubt about the weight to be put on this evidence after Bill 212, it would not be productive to engage in a point-by-point analysis of the cost of capital evidence. Instead, recognizing that there is enough variability in the cost of capital analysis (even absent Bill 212) that the results should be considered as a range of reasonable outcomes rather than a single and precise data point, the Board will consider whether the proposed return on equity and capital structure under the GRA Settlement Agreement are reasonable in the circumstances.

7.4.4 Return on Equity

[263] Under the GRA Settlement Agreement, the parties agreed to an ROE of 9% for rate setting purposes, within a range of 8.75% to 9.25%. This maintains the status quo. For rate setting purposes, it is lower than the maximum rate of return on equity allowed under s. 64AA(a) of the *PUA*.

[264] NS Power relies on the evidence it presented through the course of this proceeding to support the proposed rate of return on equity under the GRA Settlement

Agreement. The Company maintains that the evidence of its cost of capital expert witness, Mr. Coyne of Concentric Energy Advisors, justifies an even higher rate of return.

[265] As discussed already, cost of capital experts, Dr. Woolridge and Dr. Booth, filed evidence expressing their opinions that the rate of return on equity should be lower. Dr. Woolridge recommended an 8.75% ROE, while Dr. Booth's opinion was it should be 7.5%. Based on this evidence, it was open to the Board to conclude that NS Power's return on equity should be lowered, but in the circumstances, the Board finds the ROE proposed in the GRA Settlement Agreement is reasonable.

[266] In reaching this conclusion, the Board notes that although there was a more significant gap between Dr. Woolridge's recommended ROE and Mr. Coyne's, compared to the ROE proposed by NS Power, Dr. Wooldridge's recommendation is at the bottom of NS Power's existing approved range and only 25 basis points lower than the current rate of return, which is proposed to be maintained under the GRA Settlement Agreement. Further, with just one adjustment open to the Board to make on the evidence in the proceeding, Dr. Woolridge's opinion would be higher than the current rate of return.

[267] Dr. Woolridge did not apply any adjustment to his analysis for costs associated with securing equity (flotation costs). While Dr. Woolridge submitted such an adjustment was not appropriate because NS Power did not incur these costs, both Mr. Coyne and Dr. Booth adjusted their recommendations to allow for flotation costs. At the hearing, Dr. Booth explained his reasons for doing so:

> …the basic principle is simply that the equity cost is the market equity cost, what Mr. Coyne said was the secondary market, that is what investments require. So that is the building block for all of us.
>
> But in order to sell shares to the capital market, you incur flotation costs. You incur some costs. So we used to have huge litigation on this. At one point, the Régie asked Gaz Metro to go back and track all of its equity issues for almost forever and say what were the actual

> costs because the Régie took the requirement to a fair and reasonable return on actual costs literally, and they allow less than 1.5 basic points.
>
> Utility witnesses have come in and they've said they want 125, 150 basis points.
>
> So across Canada, we've sort of come to a consensus that 50 basis points was fine. That basically means the utility can earn 50 basis points more than the equity cost and the stock price will sell just a little bit above its book value. And as a result, there's no dilution of the equity value and the equity holders are treated fairly.
>
> So do I agree with 50 basis points? All I know and I agree with is we did that, and we haven't had any litigation or evidence on that, I'd say, for at least 10 to 12 years.
>
> [Transcript, September 16, 2022, pp. 1554-1556]

[268] It is a bit more difficult to reconcile Dr. Booth's overall recommendation on the appropriate rate of return on equity for NS Power with the GRA Settlement Agreement. But the Board notes that much of the criticism leveled by Dr. Booth against the opinions expressed by Mr. Coyne (and indeed, by Dr. Woolridge) was based on their reliance on market data for United States utilities and his opinion of the comparability of market evidence in Canada and the United States. In his view, return expectations in the United States are higher and cannot be applied in a commensurate manner in Canada. In his evidence, Dr. Booth said, "US financial markets exhibit more risk than the Canadian markets and have generated higher risk premia in the past."

[269] Dr. Booth's evidence includes a comparison of market risk premium estimates in Canada and the United States, but he also references two reports by Moody's. Dr. Booth commented on a passage from the second report, in 2009, in his evidence:

> Further in discussing the US and Canada Moody's stated:
>
>> "Moody's views the regulatory risk of US utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia and Canada. The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the US results in stronger competition in wholesale power markets; US fuel and power markets are more volatile; there is a low likelihood of extraordinary political action to

> support a failing company in the US; holding company structures limit regulatory oversight; and overlapping and unclear regulatory jurisdictions characterize the US market. As a result no US utilities, except for transmission companies subject to federal regulation, score higher than a single A in this factor."

Moody's went on to discuss how 4 of the 6 investor-owned bankruptcies in the US resulted from regulatory disputes culminating in insufficient or delayed rate relief for the recovery of costs and/or capital investment in utility plant. Moody's further stated, "as is characteristic of the US, the ability to recover costs and earn returns is less certain and subject to public and sometimes political scrutiny." I would emphasise here Moody's phrase "as is characteristic of the US" since this reflects how legal principles are implemented rather than differences in those principles. This phrase betrays an underlying cultural attitude towards risk that is different from Canada. I am aware that since then, Moody's has reappraised some of the effects of state regulation in the U.S and given greater weight to secured financing but the U.S is still a different country with different values.

[Exhibit N-52, pp. 102-103]

[270] Dr. Booth elaborated on these comments in his testimony at the hearing. It was likely this evidence was in mind when the Industrial Group and Dalhousie University said in their Closing Submissions "that the hearing evidence of a predictable and stable regulatory environment has been undermined" by the recent *PUA* amendments. Whether Bill 212 would influence Dr. Booth's overall assessment of risk is unclear; however, the Board considers that the mitigation of risk through regulation in Canada was a foundational element of his opinion.

7.4.5 Capital Structure

[271] Under the GRA Settlement Agreement, the parties agreed to an equity thickness of 40% for rate setting purposes, with earnings in any given year determined on an actual five-quarter average equity thickness of up to 40%. This exceeds the 37.5% currently used for rate setting purposes, although the 40% maximum equity thickness is what is currently allowed when determining actual annual earnings. It is also the maximum equity thickness under s. 64AA(b) of the *PUA*.

[272] As noted, NS Power proposed to increase its equity thickness to 45% for rate setting purposes. However, it proposed to phase this in over the test period so that rates would be set based on 38.8% equity in 2022, 41.3% in 2023 and 43.8% in 2024. In all years, NS Power proposed that its actual earnings be permitted to be determined on an equity ratio of up to 45%. As discussed above, NS Power relied on Mr. Coyne's evidence, which recommended a 45% equity thickness. Dr. Woolridge and Dr. Booth both recommended that NS Power's equity thickness for rate setting purposes be maintained at 37.5%.

[273] In its application, NS Power also said that although it proposed to phase in its requested increase in equity thickness, "the 45 percent common equity ratio put forward in the Coyne Evidence represents the minimum equity ratio NS Power forecasts as being required to maintain its current credit metrics over the 2022-2024 rate stability period." NS Power advised that, at its current rates, its cash flow-to-debt (or funds from operations) metrics would be below the levels required by DBRS and S&P to maintain its credit ratings.

[274] Dr. Woolridge questioned NS Power's assessment of its needed credit metrics to maintain its credit ratings. With reference to a June 10, 2022, S&P report [Exhibit N-127], Dr. Woolridge said S&P projected funds from operations-to-debt to be in line with a BBB+ rating. Although the report cites a base case assumption that NS Power's rates are consistent with what it proposed in its general rate application, Dr. Woolridge suggested S&P would have expected that NS Power would not have gotten everything it was asking for in its application.

[275] In response to questions from the Board at the hearing, Dr. Booth advised that the Board should be concerned about NS Power's credit metrics, but he noted they were not the only measure that bond rating agencies consider. He also cautioned that this was a "bond market problem", not an "equity market problem." He said there were other solutions to getting the bond rating up, such as issuing preferred shares.

[276] Since the hearing, and following the introduction and passage of Bill 212, NS Power's credit rating was downgraded by both DBRS and S&P. In its November 21, 2022, report, S&P said it expected NS Power's funds from operations-to-debt to be between 10% and 12% through to 2025 [Exhibit N-156, Attachment 3, p. 3]. In its December 20, 2022, report, DBRS stated:

> … While DBRS Morningstar is encouraged by the Company and the intervenors filing a negotiated settlement for the GRA, DBRS Morningstar expects NSPI's earnings and key credit metrics to be moderately weaker over the near term but to be supportive of the BBB (high) ratings. DBRS Morningstar notes that NSPI will need to find operational efficiencies and has committed to focus its planned capital expenditures (capex) on only reliability and safety projects in order to preserve its key credit metrics. NSPI's parent company, Emera Inc., has also historically been supportive of the Company by maintaining a flexible dividend payout policy and providing equity injections to maintain the debt-to-capital ratio within regulatory parameters. As such, DBRS Morningstar does not consider further negative rating actions on NSPI to be likely at this time unless there is additional political intervention in the ratemaking process that results in even higher volatility and uncertainty for the Company or leads to key credit metrics that are no longer in line with the BBB rating category. A positive rating action may occur if DBRS Morningstar sees (1) the regulatory process for the next GRA conducted free of any interference and with the NSUARB's full independence on the determination of rates, (2) meaningful progress on the replacement of coal-fired plants with renewable sources in order to meet the mandated targets, and (3) key credit metrics return to be in line with the "A" rating category.
>
> [Exhibit N-159, p. 1]

[277] In its Closing Submission, NS Power continued to rely on Mr. Coyne's evidence to support the smaller increase in equity thickness to 40% and said Bill 212 was further justification for approving the increase for rate setting purposes:

> In NS Power's view, all of this taken together, along with the overall record of this proceeding, provide the justification for the 40 percent common equity ratio included in the Settlement Agreement. However, the PUA Amendments serve to reinforce this justification as NS Power just now also operate within the constraints imposed by the PUA

> Amendments and deal with the financial implications arising from the PUA Amendments' impact on NS Power's credit ratings.
>
> [NS Power Closing Submission, p. 19]

[278] From the closing submissions filed by Intervenors who were parties to the GRA Settlement Agreement, it is clear they felt it necessary to respond to the credit rating agency response to Bill 212 by agreeing to an increase in equity thickness for rate setting purposes. NRR was the only Intervenor to expressly oppose this proposal. It questioned why Intervenors would agree to a 40% equity thickness when Dr. Booth and Dr. Woolridge recommended staying at 37.5% and submitted the Board should maintain this level based on that evidence. It submitted any increase would only increase profits to NS Power without any direct benefit to ratepayers and said if the Board determined that an increase in equity thickness was warranted, it must not exceed the 40% maximum under the *PUA* amendments.

[279] In its Reply Submission, NS Power took issue with NRR's characterization of the increase in its equity thickness as providing no direct benefit to ratepayers and with its recommendation to the Board to maintain the 37.5% equity thickness for rate setting purposes:

> The NRR submission, at paragraph 32, characterizes NS Power's approved return on equity as a return to investors "for which ratepayers receive no direct benefit." This is not correct. NS Power's Board-approved return on equity represents the just and reasonable cost NS Power pays to those who invest capital in the Company, allowing it to make the investments necessary to continue to provide safe and reliable service on behalf of customers. This cost of capital therefore provides a direct benefit to customers. Without revenue sufficient to pay the costs to obtain this capital, NS Power is not able to make such investments.
>
> …
>
> NRR's position that NS Power's current "37.5% ratio remains reasonable and should be maintained" ignores the PUA Amendments and the adverse impacts they have had, and will continue to have, for NS Power and its customers. These impacts are severe and will be long lasting. They have materially altered the assumptions and understandings used and held by the experts who provided cost of capital and capital structure evidence in this

> proceeding. This has been recognized and acknowledged by nearly every participant in this proceeding, but for NRR.
>
> [NS Power Reply Submission, pp. 9-11]

[280] Bill 212 has clearly had an impact on bond rating agencies. That is a concern to the Board as it should be to all ratepayers, and is undoubtedly why the proposal to increase NS Power's equity thickness was supported by representatives from all customer classes and the Affordable Energy Coalition which, while advocating on behalf of low-income customers, noted that a stable, appropriately financed electricity system is in the interest of every customer, including low-income customers, to ensure reliability, the achievement of environmental goals and affordability.

[281] The Board also notes that, given the choice between addressing changes in business risk by adjusting the rate of return on equity or the capital structure, Dr. Booth preferred adjustments to the capital structure:

> With a choice between capital structure versus ROE adjustments; my preference is to adjust for business risk in the capital structure for two main reasons. First, the market seems to consider any changes in the allowed capital structure to be a more permanent change, while it expects the ROE to change with capital market conditions. Since business risk is the primary determinant of capital structure, it is to be expected that a regulator will change an allowed capital structure relatively infrequently in response to significant changes in business risk. Second, allowing firms to choose their capital structure and then adjusting the ROE to a fair return runs the risk that although the equity holders are getting a fair rate of return, the overall utility income and thus rates, are too high and unfair. An extreme example here would be a regulated firm that “chooses” 100% equity financing. The regulator might then give a fair ROE, but rates are still unfair and unreasonable since the company is forgoing the tax advantages of using debt financing.
>
> One corollary to the decision of many regulators such as the CER, the BCUC and AUC to adjust capital structures in response to business risk differences is that the risk faced by shareholders in Canadian utilities is very similar. This is the very essence of why the AUC and BCUC, for example, have generic hearings on the ROE: to a great extent they have reduced differences in business risk by allowing the use of deferral accounts and altering equity ratios.
>
> [Exhibit N-52, pp. 10-11]

7.4.6 Excess Earnings

[282] In keeping with the requirement to return excess earnings to customers under s. 64C of the *PUA*, NS Power withdrew its request for a revised earnings sharing mechanism.

7.4.7 Findings

[283] Overall, the Board finds the proposed rate of return on equity under the GRA Settlement Agreement to be reasonable in the circumstances. The GRA Settlement Agreement maintains the status quo. Intervenors representing most of NS Power's customer classes supported the GRA Settlement Agreement as did the Ecology Action Centre and the Affordable Energy Coalition. No Intervenor opposed this aspect of the GRA Settlement Agreement, including NRR, who submitted "that the existing approved range of earnings should be maintained" in its Closing Submissions.

[284] The proposed rate of return is lower than the rate warranted according to Mr. Coyne and comparable to the rate recommended by Dr. Woolridge (in fact lower if a flotation adjustment is added to Dr. Woolridge's recommendation). Dr. Booth's evidence could support a lower rate of return on equity. However, given the foregoing and the Board's concerns about whether he would maintain his recommendations after Bill 212, the Board does not believe it should give Dr. Booth's evidence more weight than the other factors favouring the Board's approval of the proposed rate of return on equity in the GRA Settlement Agreement.

[285] The Board also concludes that the proposal in the GRA Settlement Agreement to increase equity thickness to 40% for rate setting purposes is reasonable.

There is no change to recovery on actual equity thickness, which is currently authorized at up to 40%. Further, while a higher equity thickness is assumed for rate setting purposes, the Board is satisfied that rates under the GRA Settlement Agreement will be based on an effective revenue requirement that is lower than it otherwise would have been in the absence of Bill 212.

[286] Additionally, the increased equity thickness for rate setting purposes received broad support from Intervenors in this proceeding, with the only party specifically opposing it being NRR. There was evidence before the Board which suggests the equity thickness should be even higher. The Board also considers that the downgrading of NS Power's credit rating must be addressed, as it poses a real risk to achieving electricity prices at the lowest long-term cost. It also impacts NS Power's ability to attract capital investment and to participate in the debt financing markets.

[287] The ROE and capital structure proposed in the GRA Settlement Agreement and approved in this decision are within the limits set in S. 64AA of the *PUA*. Any actual earnings realized by NS Power above the thresholds approved in this decision must be returned to ratepayers under s. 64C of the *PUA*. The current requirement to return any such funds through the FAM will continue, subject to the consideration of any future request by NS Power or ratepayers to refund overearnings to ratepayers through a different mechanism, including the decarbonization deferral account that may be established.

7.5 Decarbonization Deferral Account

[288] NS Power's application included a proposal to implement a DDA. In general terms, the DDA was proposed as a rate stability tool to consolidate the actual costs of the Company's transformation to 80% renewable electricity and phase out its coal-fired generating plants by 2030, and to facilitate the subsequent recovery of those costs in a transparent manner to promote rate stability and affordability for customers. Specifically, the DDA proposed in NS Power's application allowed for the following:

- Depreciation expense for coal-fired assets and associated marine unloading and fuel delivery infrastructure facilities recovered through rates for the 2022-2024 GRA is proposed to be calculated in accordance with the depreciation rates currently approved, regardless of when these assets are actually retired;

- Additional amortization of the unrecovered capital investment and decommissioning costs is proposed to be incurred to reflect full recovery of the thermal assets by their expected retirement date to allow for compliance with legislative requirements;

- The additional amortization expense is proposed to be accumulated in the DDA regulatory asset, resulting in a movement of the unrecovered amounts from plant-in-service to a regulatory asset;

- Other prudently incurred costs incremental (or decremental) to the amount included in NS Power's revenue requirement associated with the Company's obligation to meet the legislative requirements would also be included in the DDA. As discussed previously, these items would include both direct and indirect costs associated with the transition to more clean energy and may include depreciation expense and financing costs on assets to support the transition to clean energy, additional decommissioning expense incurred on thermal assets, incremental operating and maintenance expense, employee transition costs, and write-off of materials and fuel inventory for thermal generating facilities that are no longer required, and termination costs associated with fuel supply contracts;

- The DDA regulatory asset is proposed to be recovered over future periods. The amount of proposed recovery in future periods will take into account affordability for customers and timely recovery of the costs and will be subject to NSUARB approval; and

- The DDA regulatory asset is proposed to be included in rate base as the balance accumulates.

[Exhibit N-16, pp. 49-50]

[289] With respect to the early retirement of NS Power's thermal assets by 2030, NS Power indicated that the DDA would serve as a regulatory asset that effectively eliminates the requirement for a depreciation study for these assets. The Company noted

that reclassifying the unrecovered costs of these assets from plant-in-service to an approved regulatory asset would allow for increased flexibility in the timing of recovery of these costs to the benefit of NS Power's customers and the Utility as the costs would no longer need to be depreciated over the remaining useful life of the assets. Instead, these costs could be recovered over an appropriate timeline in the future, which would be intended to best balance customer affordability with the timely recovery of the costs.

[290] The Intervenors expressed varied opinions about the DDA proposed in NS Power's application. Board Counsel consultant, Grant Thornton, noted that the DDA provides a reasonable mechanism to capture additional amortization of unrecovered thermal asset capital investment and decommissioning costs by the expected retirement dates. They also stated that the DDA gives NS Power and the Board flexibility in the timing of the recovery and allows NS Power to not propose recovery of these costs through accelerated depreciation in revenue requirement in this GRA. However, Grant Thornton was not able to support NS Power's position on the direct and indirect costs element of the DDA, believing that more information is needed around the costs to be incurred.

[291] Daymark recommended that the DDA should not include accelerated depreciation due to anticipated early retirement; however, it should be used to recover undepreciated balances of early retired generation after retirement occurs. They also suggested that the eligibility of DDA investments should be established as part of ACE proceedings, and that costs that are normally expensed should be prohibited from being incorporated into a DDA. Further, Daymark noted that the DDA may be helpful to demonstrate a lower risk regulatory environment in Nova Scotia.

[292] Melissa Whited, Board Counsel consultant, stated that the DDA, as proposed in the application, is not reasonable, as its scope extends far beyond accelerated retirement costs. She recommended that the DDA be rejected, and that NS Power instead address the costs associated with early retirement of thermal assets through its existing Accounting Policy 6350. This policy states that in order to enhance rate stability, where a write off is significant and Board approval is obtained, the undepreciated cost of the asset should be amortized, on a straight-line basis, over five years or over a reasonable period, subject to Board approval. The unamortized cost may remain in rate base, and any cost of capital should be expensed in the period incurred.

[293] Resource Insight agreed with NS Power that regulatory assets, including deferral accounts and other similar accounting mechanisms, can reasonably be used to address retirements and unusual investments. However, Resource Insight was concerned that almost any future capital costs could be associated with the transition to clean energy and eligible for inclusion in the DDA. They opined that this would eliminate the linkage between established practices for determining depreciation rates. Therefore, similar to Ms. Whited, they recommended that NS Power's proposal to include costs associated with early retirements, including uncollected decommissioning costs, in the DDA be rejected. They believe there is no compelling reason to develop entirely new accounting policies to handle the amortization costs associated with early retirements. They did not object to the Board considering revisions to Accounting Policy 6350 to allow for amortization of regulatory assets to extend longer than five years. Resource Insight also recommended that indirect costs and savings associated with Eastern Clean Energy Initiative (ECEI) capital project costs should be excluded from the DDA or any other

authorized deferral account. Further, they recommended that NS Power establish a capital tracker deferral accounting mechanism (which could be named DDA) for the four ECEI projects.

[294] Mark Drazen, on behalf of the Industrial Group and Dalhousie University, stated that NS Power's application for approval of the DDA involves a rather open-ended approach to the costs that might be transferred to the account. He, therefore, recommended that the Board reserve judgment on the DDA until the Board and ratepayer stakeholders can study potential effects.

[295] With respect to the treatment of early retirement of NS Power's thermal assets, Christine Runge, of behalf of NRR, opined that the question left to the Board in this proceeding is essentially one of rate shock and the associated strategy to mitigate the impacts. She stated that the Board must determine to what extent the bill impacts are a concern and if there is adequate value from the mitigation of bill impacts to justify the higher total costs to customers. Ms. Runge recognized that the DDA could potentially be the best option for recovery of costs associated with the early retirement of thermal generation assets. However, her evidence noted that this could not be confirmed based on the information provided on the record of this proceeding. As such, she recommended that the Board not approve nor reject the DDA until NS Power files the following information so that the proposed DDA can be more thoroughly evaluated:

- a new depreciation study, the associated rates required to collect the costs in that manner, and the bill impacts of this approach;
- the amounts by generator that are expected to remain undepreciated on the forecast date of retirement, the annual rate impact of collecting those costs over five-year periods under Accounting Policy 6350, and the bill impacts of this approach; and

- a forecast of the dollar value of the DDA at the time collection begins, guidance on the amortization period that may be required, the increase in total costs paid by consumers from this alternative, and the bill impacts of this approach.

[296] With regards to the inclusion of future generation assets in the DDA, including the recovery of direct and indirect costs associated with the transition to clean energy, Ms. Runge stated that such costs are all business-as-usual costs that NS Power should be able to manage under its Cost of Service (COS framework). She, therefore, recommended that this element of the proposed DDA be rejected by the Board.

[297] Under the terms of the GRA Settlement Agreement, the signatory parties have agreed, in principle, to a DDA to recover NS Power's undepreciated thermal asset Net Book Value (NBV) and unrecovered decommissioning costs. They have also agreed to engage constructively in a consultative process to confirm the practice and procedures that will be followed to establish the DDA and its scope, to affect the transfer of unrecovered costs to a regulatory asset and to recover such costs. This process will result in NS Power providing a report to the Board describing the results of the consultative process and seeking approval of the DDA by June 30, 2023. For greater certainty, the GRA Settlement Agreement confirms that the Board's decision in [2012 NSUARB 133] with respect to the MEUs responsibility for the payment of stranded costs continues to apply and is not affected by the DDA agreement in principle. The parties have also agreed to discuss the potential for the application, approval, and implementation of the DDA, or similar mechanism, as it relates to "New Capital Assets" and "Incremental/Decremental OM&G costs", as those are described in Section 4.1 of NS Power's Rebuttal Evidence (i.e., energy transition investment and related costs).

7.5.1 Findings

[298] In the Board's view, it is important to note that the DDA, as presented in NS Power's application, was proposed by the Company in the context of the requirement to retire a significant amount of thermal assets, as provincial and federal policymakers desire transformative change to reduce carbon and emissions on an accelerated timeline:

> A significant part of the transition will require the retirement of a large amount of thermal generating stations fueled by coal and other fossil fuels. For regulated utilities, their investments in thermal assets were made to serve customers under what is known as the Regulatory Compact…For these assets, which face the need for cost recovery beyond traditional depreciation levels due to the Energy Transition, significant work is being undertaken by utilities and regulators to determine the form and timing of their cost recovery, and how to optimize their value in the interim. Well-established regulatory principles require that utilities be provided the opportunity to recover prudently-incurred costs, even if such assets should become subsequently under-utilized or retired earlier than previously expected, especially when the cause of those outcomes is a change in legislation or regulatory policy. The Energy Transition is creating the need to shift away from the use of thermal assets, and to confront the retirement of assets where such actions are necessary to meet environmental mandates for carbon reduction or otherwise provide net savings to customers.
>
> [Exhibit N-17, Appendix 7A, p. 10 of 72]

[299] In this context, NS Power is a utility regulated under a cost of service model. This means the Company is allowed to recover its prudently incurred costs in the provision of service to customers and may earn a reasonable return on its related invested capital. Therefore, where the Company has made an investment to the benefit of customers but related prudently incurred costs of capital have yet to be recovered, NS Power may recover these costs even after capital assets have been retired, in circumstances where the assets were retired due to changes in public policy beyond its control. Further, since the costs have yet to be recovered, there are still debt and equity financing costs associated with these investments. None of the parties in this proceeding have suggested that NS Power is not entitled to recover such costs.

[300] This notwithstanding, in its Closing Submission, NRR submitted that NS Power's request for approval of a DDA should be denied. In support of this submission, NRR argued that the mechanics of the DDA remain unclear, and there are other existing mechanisms available to NS Power that it can use to address depreciation concerns. In particular, while NRR did acknowledge that a DDA could potentially be a useful tool, NRR contends that NS Power did not present sufficient information to assess the DDA's utility relative to other options.

[301] With respect to the use of a DDA to address the early retirement of NS Power's thermal assets, as proposed in the GRA Settlement Agreement, the Board disagrees with NRR's contention that it should be denied.

[302] First, the GRA Settlement Agreement is not proposing approval of the DDA at this time. It is clear that the GRA Settlement Agreement represents only an agreement in principle among the signatories with regard to a DDA for accelerated depreciation costs associated with NS Power's undepreciated thermal asset NBV and unrecovered decommissioning costs. An application for approval of such a DDA has yet to come before the Board. Further, the specifics of how the DDA will work are proposed to be developed in a stakeholder consultation process. This process will result in NS Power providing a report to the Board describing the results of the consultative process and seeking Board approval of the DDA by June 30, 2023.

[303] In addition, in response to NRR GRA Settlement Agreement IR-11(c), NS Power confirmed that the GRA Settlement Agreement rates for 2023 and 2024 do not include any costs related to the DDA. As such, the Board finds that the DDA will not impact 2023 and 2024 rates proposed in the GRA Settlement Agreement.

[304] The Board agrees with NRR and other Intervenors that there are other options available to NS Power to address recovery of costs associated with the early retirement of the Company's thermal assets. Nevertheless, based on the proposed GRA Settlement Agreement, the Board must address whether a DDA provides an appropriate means to recover these costs. The Board finds that it does for the reasons described as follows.

[305] First, as confirmed during the hearing, NS Power's ability to recover costs associated with early retirement of thermal capital assets does not vary between a scenario in which the DDA is approved and the current means of cost recovery:

> **Q.** (Murphy)…in your rebuttal evidence on page 27, lines 9 to 12, when you refer to retirement of the coal plants, you note that:
>
> > Financing costs associated with these thermal assets are included in revenue requirement and embedded in proposed rates. When the unrecovered amounts associated with these assets are moved to the DDA account, [Nova Scotia] Power proposes to continue expensing these costs and there will be no financing costs associated with these assets deferred and added to the DDA.
>
> …So is this -- specifically, does this mean that there will be no increase in overall financing costs because the transfer to the DDA in fact won't result in a change to rate base and it won't change any depreciation expenses associated with those assets? I think that's what you were saying yesterday, but I just want to make sure.
>
> **A.** (Flemming) Yes, that is correct.
>
> **Q.** Okay. That was a long way of getting to an answer, but thank you.
>
> So can you confirm that once a coal plant is retired and it's no longer in property, plant, and equipment, can you confirm that the amount for that particular asset that's in the DDA will be amortized at current depreciation rates until the DDA amortization period is set?
>
> **A.** (Flemming) Yes, that's correct. We're proposing to keep -- well, to redirect funds that would have previously been to depreciate the cost of property, plant, and equipment to amortization of the DDA as to not decrease Nova Scotia Power's revenue requirement as a result of moving these assets to the DDA.
>
> [Transcript, September 14, 2022, pp. 654-656]

In effect, upon retirement of these assets, the depreciation expense in rates would be directed to amortization of the DDA regulatory asset, until such time that a DDA amortization period is set by the Board.

[306] Further, the Board has regulatory tools to manage rate impacts on customers when the recovery of capital assets over a period does not match the underlying life of an asset. With the DDA, until the amortization period is set, there will be no rate impacts. Moreover, any future rate impacts can be addressed in separate proceedings with customers where the Board will have flexibility to manage rate impacts and affordability. As noted by Mr. Reed in his evidence:

> As it is currently conceived, approval and implementation of the DDA would not bring any immediate rate impacts. The DDA is designed for the transferring and tracking of decarbonization-related costs into a single account. A subsequent regulatory proceeding would need to be initiated, an amortization period established, cost allocations and rate impacts determined, and Board approval received, before rate impacts would flow through to customers.
>
> [Exhibit N-17, Appendix 7A, p. 25 of 72]

[307] The Board also finds that a DDA to recover costs associated with early retirement of thermal capital assets offers superior benefits to other cost recovery mechanisms available to NS Power, particularly Accounting Policy 6350. Specifically, addressing these retirements under Accounting Policy 6350 would result in numerous deferral accounts with varying impacts to revenue requirement and potentially different amortization terms. This issue was discussed extensively during the hearing:

> **Q.** (MacDonald) So I recognize from evidence heard today and yesterday, that under -- I believe if we were to see these assets depreciate individually, or amortize, rather, as individual assets, that we may see multiple potential amortization accounts – amortization deferral accounts. Is that correct?
>
> **A.** (Flemming) Yes, that's absolutely correct. As Mr. Reed spoke to earlier, the current process with accounting policy 6350, if we were to retire these assets and amortize them, as the policy is currently written, you would have a separate amortization, a separate amortization account for each of these retiring assets. They would be fixed in nature and, you know, that's, I think, a drawback to the current practice that we have of application of the 6350, setting the amortization period. It's not as flexible as the proposed DDA, and

> really, it doesn't acknowledge the fact that we're looking at a whole system transformation, as Mr. Ferguson spoke to earlier.
>
> **Q.** I take it, though, that this individual amortization deferral accounts would be scrutinized as individual accounts as opposed to the -- as I believe the panel and maybe Mr. Reed refer to it as yesterday -- the pot. Is that correct?
>
> …
>
> **A.** (Flemming) It accumulates all the costs in one -- in one account. And so instead of having, as Mr. Reed spoke to, 10, 11 different amortization accounts, and then maybe you need flexibility and you don't have just 10 or 11 decisions, now you have 40, 50, upwards decisions. So we think that that is a key -- that looking at it on the holistic and acknowledging the total power system transformation is a key benefit.
>
> However, the scrutiny associated with the remaining asset balances, the scrutiny with any balance that gets added to the DDA, we would expect and anticipate that there will be full Board review and full transparency of any of these balances.
>
> [Transcript, September 13, 2022, pp. 415-418]

[308] The extent of individual deferral account requirements under Accounting Policy 6350 would result in excessive regulatory burden and costs. In contrast, the DDA mechanism consolidates the balances associated with these unrecovered capital assets, is holistic in nature and is simple to administer.

[309] NRR has argued that deferral mechanisms, such as the DDA, can mitigate rate shock to consumers in the short term, but over time the total amount payable is increased because of interest chargeable to ratepayers for financing the deferral. The Board notes, however, that use of Accounting Policy 6350 would also result in such cost deferrals and related financing charges. In the Board's view, the flexibility inherent in the DDA, as compared to Accounting Policy 6350, allows for simpler adjustments to amortization and revenue requirements that better balance timely recovery of costs and affordability for customers while considering other cost pressures facing NS Power and customers. Finally, as noted by the CA:

> …the establishment of a thermal asset DDA provides a single gathering place for the significant cost associated with the early retirement of the thermal assets. The early retirement of the thermal assets was mandated by various levels of government. The

> thermal asset DDA will provide transparency regarding the substantial costs faced by Nova Scotia ratepayers as a result of government-imposed asset retirements.
>
> [CA Closing Submission, pp. 3-4]

[310] Based on the above, the Board finds that the proposed DDA provides a mechanism that will allow better flexibility in the recovery of investment in thermal assets that will be phased out due to the decarbonization transition. It will also effectively balance timely recovery of the related costs with customer affordability. The Board also notes that the DDA is not intended to make unrecoverable costs recoverable by NS Power. Instead, it will allow for NS Power's recovery of prudently incurred costs while making the transition to increased renewables to 2030 and beyond more affordable for customers.

[311] The Board, therefore, approves a DDA in principle to recover NS Power's undepreciated thermal asset NBV and unrecovered decommissioning costs. This approval is subject to stakeholders engaging in a consultative process to confirm the practice and procedures that will be followed to establish the DDA and its scope, to effect the transfer of unrecovered costs to a regulatory asset and to recover such costs.

[312] To be clear, the Board is not approving a formal DDA at this time. Instead, the Board will wait for a report submission by NS Power describing the results of the stakeholder consultative process. The Board will only consider approval of implementation of a DDA after submission of that report and a formal application for approval by NS Power.

[313] The Board also confirms that its decision in [2012 NSUARB 133] with respect to the MEUs responsibility for the payment of stranded costs continues to apply and is not affected by the Board approval of the DDA agreement in principle.

[314] Notwithstanding the Board's approval of the DDA in principle to recover costs associated with early retirement of thermal capital assets, the Board agrees with the Industrial Group and Dalhousie University that all matters surrounding the DDA remain open for discussion with stakeholders, including the future possibility of securitization as an alternative to financing at WACC. As such, the Board believes it would be useful at this stage to identify some of the items it believes need to be addressed through a DDA stakeholder consultative process. These issues include, but are not limited to:

- Assets to be included in the DDA;
- Timing of transfers to the DDA;
- Unrecovered plant balances at the time of transfer to the DDA;
- Rationale for selection of future amortization periods;
- Appropriate rate of return on the DDA;
- Potential use of securitization;
- Tracking of sustaining capital costs per plant until retirement;
- Continuity schedule per plant;
- Annual DDA reporting requirements; and
- Identification of expected and unrecovered decommissioning costs, as offset by COR and ARO.

[315] NS Power is no longer seeking Board approval of a DDA mechanism to recover other energy transition related costs. Nevertheless, the parties to the GRA Settlement Agreement have agreed to discuss this issue further. Specifically, the GRA Settlement Agreement includes a provision to continue stakeholder discussion about the potential application, approval, and implementation of a DDA or a similar mechanism as it relates to incremental or decremental revenue requirements associated with the ECEI projects; and direct costs (OM&G and depreciation expense) and indirect costs (financing and income tax) associated with the transition to clean energy that are not included in the Company's revenue requirement. This provision of the GRA Settlement Agreement

provides an opportunity to discuss potential DDA terms and conditions during stakeholder consultation and address any related concerns of stakeholders and the Board. The Board approves of stakeholders proceeding with this consultation.

7.6 Storm Rider and Climate Change Adaptation Plan

[316] NS Power's application includes OM&G costs for storm restoration in its revenue requirements. NS Power proposed a base rate allowance for Level 1/Level 2 storm restoration OM&G costs and a base rate allowance for Level 3/Level 4 storm restoration OM&G costs. NS Power classifies storms as follows:

- Level 1 – Regional Service Restoration Response: less than 50,000 customers affected, and restoration expected to be completed within 12 hours.
- Level 2 – Multi-Region Service Restoration Response: less than 50,000 customers affected, and restoration expected to be completed within 36 hours, or more than 50,000 customers affected but restoration expected to be completed within 24 hours.
- Level 3 – Provincial Service Restoration Response: less than 50,000 customers affected, and restoration expected to require more than 36 hours, or more than 50,000 customers affected but restoration expected to be completed within 72 hours.
- Level 4 – Corporate Service Restoration Response: more than 50,000 customers affected, and restoration expected to require more than 72 hours.

[317] In its application, NS Power proposed the following base rate allowances for storm restoration OM&G costs:

($ millions)	**Level 1 and 2 Storm Costs**	**Level 3 and 4 Storm Costs**
2022	$7.3	$10.5
2023	$7.2	$10.2
2024	$7.3	$10.4

[318] The 2022 forecast was determined by taking the average storm restoration OM&G expense from 2016 to 2020 and removing the Post-tropical Storm Dorian extreme

storm event. This amount was then escalated for inflation and adjusted for forecast savings due to the implementation of AMI technology. NS Power's exclusion of the impact of Post-tropical Storm Dorian is due to the Company's proposed Storm Rider (to be discussed in the following sections). Absent approval of the proposed Storm Rider, NS Power's budget for storm restoration expense was proposed to increase by $3.5 million each year.

[319] The Company noted that Level 3 and 4 storm events and the associated costs for timely customer outage restorations are becoming more substantial and largely beyond the ability of the Utility to predict precisely or control. NS Power stated that this circumstance exists across the industry and is becoming more challenging with the impacts from global climate change. Further, the Company noted that its 2014 OM&G storm restoration expense included in the 2013-2014 GRA compliance filing was $10.8 million, while its storm restoration expense has exceeded that level in each year from 2016 to 2020.

[320] The occurrence of one or more extreme storm events within a year could result in actual storm restoration OM&G expense that is significantly higher than the amount included in NS Power's revenue requirement. To avoid including estimated costs for such extreme events in base rates, NS Power has proposed a storm restoration deferral and recovery mechanism (Storm Rider) for approval as part of this GRA. The requested Storm Rider would apply to storm restoration OM&G costs exceeding those included in the Level 3/Level 4 storm costs forecast in any given year. It would not apply to costs exceeding Level 1/Level 2 forecast storm costs.

[321] The proposed Storm Rider has the following key elements:

- The Level 3 and Level 4 storm costs forecast, determined in the manner described above, will be included in the revenue requirement and base rates.

- Actual Level 3 and Level 4 storm costs will be tracked throughout the year and, at the end of the first quarter of each year, the prior year actual costs will be determined and compared to the amount included in customer rates.

- If the actual results exceed the amount included in the revenue requirement, the Company, at its discretion, will apply to the Board for a charge (the Storm Rider) to be applied to recover the shortfall effective January 1 of the following year. The Company will endeavour to make this application by April 30.

- All non-capital preparation, response, and restoration related costs associated with Level 3 and Level 4 storms will be eligible for inclusion in the Storm Rider, including (1) storm preparedness including crew staging and related logistical expenses; (2) incremental NSPI wages, benefits, and overtime pay related to storm recovery; (3) costs of external service providers and mutual aid utilities hired by the Company during restoration efforts; (4) materials and supplies used to repair damaged assets and any associated expenses; and (5) other recoverable expenses, including extra costs for temporary repairs and to expedite the permanent repair of damaged property and expenses incurred for providing services to customers whose electric service has been interrupted.

- Eligible storm costs to be included in the Storm Rider in any given year cannot exceed 2 percent of that year’s forecast retail revenues of the Company. Any eligible storm costs in excess of the 2 percent cap will be deferred to the subsequent year’s Storm Rider.

- The initial costs included in the Storm Rider for a specific year are based on annual actual results, and so will not change once they are determined. Actual volumes billed to customers, however, may vary from projections, leading to over- or under-recovery of storm costs. Any such over- or under-recoveries of the costs included in the Storm Rider will be determined at the end of each year and included in the calculation of the subsequent year’s Storm Rider.

- The cost of financing the deferral will be calculated at NS Power’s approved Weighted Average Cost of Capital and added to the deferral balance.

[Exhibit N-16, pp. 105-106]

[322] In response to an IR from NRR, NS Power explained its inclusion of Level 3/4 costs and exclusion of Level 1/2 costs in the proposed Storm Rider as follows:

> Figure 12-4 of the Application provides annual storm costs from 2016 to 2020 for Level 1 and Level 2 storms and Level 3 and Level 4 storms. The Level 1 and Level 2 storm costs range from $4.8 million to $9.5 million. The Level 3 and Level 4 storm costs are significantly more variable and material, ranging from $6.4 million to $22.3 million annually. While all storms are outside of the utility's control, it is the volatility, the materiality and difficulty in accurately forecasting the annual Level 3 and Level 4 storm costs that the Company is seeking to address through the proposed Storm Rider.
>
> [Exhibit N-40, Response to IR-20, p. 1]

[323] NS Power also proposed that Level 3/Level 4 storm restoration OM&G costs exceeding the Company's base rate Level 3/Level 4 cost allowance would be allocated to each rate class, consistent with the allocation of storm response costs in the cost of service. The Storm Rider rate would be applied based on projected sales (in kWh) by rate class. Further, the earliest a Storm Rider could take effect would be 2025 for 2023 costs.

[324] Concentric, on behalf of NS Power, indicated that the use of adjustment clauses (that operate through rate riders) and deferral and variance accounts has grown over time, and the use of such non-base rate mechanisms to track and recover costs is prevalent throughout the North American utility industry. Concentric noted that these types of cost recovery mechanisms tend to focus on the recovery of costs that are: (1) volatile and/or difficult to project, (2) potentially significant, and (3) generally outside of the utility's control. As such, since Level 3 and 4 storm restoration costs meet these criteria, Concentric argued that the associated OM&G costs are well suited for recovery through the proposed Storm Rider. Concentric also believes that the proposed Storm Rider is an appropriate mechanism to help address the challenges facing the Company over the coming decade, and is in line with industry precedent.

[325] For the most part, the Intervenors did not object to the imposition of the Storm Rider. In fact, Ms. Whited, on behalf of Board Counsel, noted that a rider can be

a reasonable method for recovering major storm costs that are outside the control of the utility. However, a number of parties took issue with the Storm Rider's asymmetric construct. They believe that the proposed Storm Rider is inequitable because actual Level 3 and 4 storm restoration OM&G costs over the base rate allowance are eligible for recovery, while there is no provision for a refund to customers if actual costs are below the base rate allowance. These parties recommended that the Storm Rider mechanism be adjusted to capture both cost under-recoveries and over-recoveries. Ms. Runge, on behalf of NRR, further recommended that the Storm Rider be adjusted to include Level 1, 2, 3 and 4 storm restoration OM&G costs. Daymark, on behalf of the SBA, suggested that the Storm Rider would be helpful to demonstrate a lower risk regulatory environment in Nova Scotia. Daymark also recommended that each Storm Rider application include a review of NS Power's preparation, storm response, the legitimacy of outages duration, and the prudency of system hardening planning.

[326] Under the terms of the GRA Settlement Agreement, the signatories have agreed to accept the imposition of the proposed Storm Rider only for the years 2023, 2024 and 2025 (for recovery, if applied for by NS Power, from 2025 to 2027). During this period, the signatories have agreed that the Storm Rider construct will be as per the Storm Rider Direct Evidence PR-01 page 106 and PR-01 Att1v, but, modified as per Section 13 of NS Power's Rebuttal Evidence, to eliminate the volume provision of the Balance Adjustment from the Storm Rider. The signatories have also agreed that NS Power will have the option to apply to the Board for recovery of costs through the Storm Rider if Level 3 and Level 4 storm restoration expenses exceed $10.2 million in 2023, $10.4

million in 2024, and $10.4 million in 2025. The GRA Settlement Agreement notes that the Storm Rider will terminate after recovery of costs from 2025.

7.6.1 Findings

[327] The issue of whether the forecast savings, due to the implementation of AMI technology, were properly applied by NS Power to its Level 1, 2, 3 and 4 storm restoration OM&G base rate allowances was discussed extensively during the hearing. In particular, a number of parties noted that NS Power may not have properly reflected anticipated 10% OM&G cost savings in the base rate allowances, as had been identified in the Company's original AMI application, approved by the Board (Matter M08349). Upon questioning by the Board, NS Power explained how it applied the projected savings. The Board accepts this explanation. Therefore, it finds that AMI savings have been properly applied to storm restoration OM&G base rate allowances.

[328] In its Closing Submission, NRR argued that the proposed Storm Rider, as presented in the GRA Settlement Agreement, is not necessary and is not in the best interests of ratepayers. One of NRR's primary concerns is about the asymmetric nature of the proposed rider, as expressed by several Intervenors. The Board too had concerns about the rider's asymmetric construct as presented in NS Power's original application. However, the Board finds that the GRA Settlement Agreement effectively lessens these concerns by providing a three-year trial period over which the Storm Rider's effectiveness, equity and whether it is, in fact, in the best interest of ratepayers, can be thoroughly tested.

[329] The Board also agrees with the Industrial Group's Closing Submission asserting that the recent *Public Utilities Act* amendments capping non-fuel rates at 1.8%

mitigates the concerns about the asymmetric design of the Storm Rider and reduces the risk of NS Power over-collecting storm restoration OM&G costs in base rates for this GRA.

[330] NRR also asserted that NS Power's proposed Storm Rider is reactive rather than proactive. NRR referenced the hearing testimony of Mr. Dane, where he referred to the Storm Protection Plan Cost Recovery Rider (SPPCRR) proactive storm recovery mechanism in Florida. However, as noted by NS Power in its Reply Submission, Florida utilities also use another storm restoration cost recovery mechanism similar to NS Power's proposed Storm Rider. This was confirmed by NRR's own expert witness, Mr. Dalton, where he noted in his evidence that Florida utilities have typically been allowed to recover storm restoration costs on a retrospective basis.

[331] In his Closing Submission, the CA stated:

> - Storm Rider - Unlike the Storm Rider applied for by Nova Scotia Power, the Settlement Agreement Storm Rider has a maximum term of 36 months. It is the view of the Consumer Advocate that a definitive time period effectively provides for a trial implementation of a Storm Rider. The trial period can be used to assess whether a Storm Rider (in a more permanent form) is in the best interest of rate payers. In addition, the trial Storm Rider provides an opportunity for an additional consideration and assessment of system reliability and service restoration times - which are essential concerns for residential ratepayers.
>
> [CA Closing Submission, p. 4]

[332] The Board agrees with this assessment, and approves the Storm Rider as described in the GRA Settlement Agreement. In addition, the Board directs NS Power to submit annual reports summarizing actual storm restoration costs for each year of the trial period. This reporting is to include a summary of actual Level 1, 2, 3 and 4 storm restoration costs. It shall indicate the monetary amount of any Level 1/2 and Level 3/4 cost underruns or overruns from base rate allowances. These annual reports shall be submitted by April 1 of each year in 2024, 2025 and 2026. At the end of the three-year trial period, the reports will be used to help assess the effectiveness and equity of the

Storm Rider, whether the Storm Rider remains in the best interest of ratepayers and whether adjustments to its construct are required.

[333] NRR stated that the GRA Settlement Agreement Storm Rider does not encourage NS Power to take reasonable efforts to harden its system or mitigate the storm restoration costs that will be passed along to ratepayers. NRR argued that instead, NS Power seeks to recover Storm Rider costs from ratepayers without any accountability for the reasonableness of NS Power's own mitigation efforts. NRR recommended that, should the Storm Rider be approved, any assessment of the reasonableness of costs incurred and subject to the Storm Rider should include an analysis of not only the prudency of costs for restoration, but also of the Company's efforts to harden the system and mitigate storm costs in advance of extreme weather events.

[334] The GRA Settlement Agreement appears to be silent on this issue. In addition, the Board finds that NS Power's Reply Submission is somewhat vague on the matter and suggests that such a review would be subject to only a prudency review of the Storm Rider costs. However, this issue was discussed extensively during the hearing. In particular, the following exchange occurred during questioning of NS Power by the CA:

> **Q.** (Mahody) In the event this storm adjustment mechanism or rider is approved as you've applied for it, as we come to that first hearing in 2024, and let's say -- and let's say there's an extra $2 million in costs all relating to Level 3 and 4 storms, the reality, though, is that there's the amount that's in rates for Level 3 and 4 if your application goes forward as applied for, and then you're talking about the incremental difference, say, of a couple million dollars.
>
> Do you agree with me that you need to -- it needs to be a full review of all Level 3 and 4 storm costs in order to be able to consider that incremental amount and the reasonableness and prudence of that incremental amount?
>
> **A.** (Ferguson) I do.
>
> [Transcript, September 20, 2022, pp. 1694-1695]

[335] Based on this exchange, it appears to the Board that NS Power partially agrees with the position taken by NRR. Further, as noted by Ms. Runge in her evidence:

> 83. It is also important to note that while the existence of a storm and the need to repair damaged assets is outside of the utility's control, the amount spent to repair those assets is within the utility's control.
>
> [Exhibit N-48, p. 25]

[336] The Board, therefore, finds it is appropriate for a review of a Storm Rider cost recovery application to include a full review of all Level 3 and 4 storm restoration costs for the applicable year, not just those Level 3 and 4 storm restoration OM&G costs that exceed base rate allowances.

[337] Moreover, the costs associated with NS Power's storm hardening and vegetation management efforts (beyond those associated with storm restoration) are also within the Company's control. The Board has no doubt that these efforts can have a direct impact on the magnitude of required storm restoration costs. Therefore, the Board agrees with NRR that a Storm Rider cost recovery review needs to assess not only all Level 3 and 4 storm restoration costs, but all costs expended by NS Power in the related year aimed at storm hardening, including vegetation management costs.

[338] Therefore, the Board finds that when NS Power submits a Storm Rider cost recovery application for Board approval, it is appropriate for the assessment of the application to include a full review of all storm restoration costs (including capital expenditures), storm hardening costs and vegetation management costs during the related year. The Board directs NS Power to include full detail on all these costs in each Storm Rider cost recovery application submitted during the three-year trial period. In advance of the first Storm Rider cost recovery application, the Board further directs NS

Power to engage with stakeholders to determine the specifics for how this information is to be presented.

[339] The Board also notes that in its response to Board IR-171 [Exhibit N-69], NS Power identified a number of steps it is taking to address the challenge of a changing climate, as well as to meet increasing expectations from customers to mitigate risks from severe weather events. The Board is aware that utilities in other jurisdictions have developed formal climate change adaptation plans. For example, Hydro-Québec recently released a Climate Change Adaptation Plan for 2022-2024. Additionally, the Board understands that organizations like Electricity Canada and the Electric Power Research Institute have developed guidance documents for utilities to develop such plans and climate change adaptation strategies.

[340] It is not clear to the Board whether the items identified by NS Power in its response to NSUARB IR-171 are part of a formalized Climate Change Adaptation Plan adopted by the Company. The Board considers that the implementation of such a plan, through a consultative process, may be useful in demonstrating the prudency of storm restoration costs in Storm Rider cost recovery applications, would engender confidence in such a rider if NS Power seeks to implement one after the period covered by the GRA Settlement Agreement, and would enhance NS Power's capital expenditure processes and integrated resource planning. As such, NS Power is directed to engage in a consultative process to develop a Climate Change Adaptation Plan to be filed with the Board no later than the end of 2025. As with the COSS and Line Loss Study discussed later in this decision, the Board approves the deferral of the costs of developing this plan for recovery through rates after NS Power's next general rate application.

[341] Finally, in its Closing Submission, NRR asserted that NS Power has been delinquent in its investments in system reliability, particularly related to vegetation management. NRR stated that 90% of power outages in Nova Scotia occur because of downed trees falling on power lines. It argued that even in this context, NS Power's OM&G vegetation management costs for 2018, 2020 and 2021 have been significantly below its twelve-year average. NRR goes on to state:

> 20. NSP's responses to the Consumer Advocate's questions on vegetation management suggest that investment towards vegetation management is not consistently focused on distribution, highlighting a deficiency in NSP's operational priorities which would reasonably be expected to impact reliability of service.
>
> …
>
> 22. …NRR takes the position that NSP's maintenance budget is some combination of deficient and misallocated to purposes that do not offer sufficient return to ratepayers in terms of system reliability.
>
> [NRR Closing Submission, p. 5]

[342] However, the Board agrees with NS Power in its Reply Submission, where the Company notes that NRR's focus on only OM&G vegetation management costs does not provide a full picture of NS Power's vegetation management investment. NRR's position ignores the capital investment that NS Power has made with respect to vegetation management. Undertaking U-39 asked NS Power to provide a table describing the Company's vegetation management costs from 2010 to 2021, including distribution and transmission OM&G and capital costs. The response to Undertaking U-39 provided as follows:

2010-2021 Vegetation Management Costs ($ million)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020*	2021
Operating Expense	8.9	7.9	8.5	8.4	8.0	7.1	5.7	11.2	5.2	11.5	4.2	4.2
Capital Investment	0.7	0.9	1.0	2.2	0.8	1.2	7.0	11.1	19.1	14.3	10.4	16.4
Total Expenditures	**9.6**	**8.8**	**9.5**	**10.6**	**8.8**	**8.3**	**12.7**	**22.3**	**24.3**	**25.8**	**14.6**	**20.6**

* Vegetation management spending in 2020 was only $14.6 million because of operational restrictions during the height of the COVID-19 pandemic.

This table clearly shows that NS Power's total expenditures on vegetation management has increased significantly over the past five years.

[343] The Board also notes that NS Power's capital expenditures over $1 million related to system reliability, storm hardening and vegetation management are reviewed by the Board for prudency. Additionally, the Board continues to review NS Power's system reliability performance through the annual Performance Standards Review proceeding.

7.7 DSM Rider

[344] In its application, NS Power requested Board approval of a Demand Side Management Cost Recovery Rider (DCRR) to recover costs associated with DSM programs developed and delivered by EfficiencyOne, a third-party regulated utility. NS Power stated that it does not control the magnitude or scope of those programs, their execution, or the establishment of the funding levels. Those aspects are managed by EfficiencyOne and Board approval is required under a public regulatory process.

[345] Accordingly, NS Power stated that it is not appropriate or necessary for it to accrue positive or negative cost variances in DSM program spending. It noted that alignment of utility revenues with actual costs and promotion of regulatory transparency and efficiency would be achieved if DSM costs were segregated from its revenue requirement for separate tracking and recovery under the DCRR.

[346] In this matter, NS Power's proposed DCRR was initially based on DSM expenditures of $39 million during each of 2023 and 2024. This was later updated to

align with the expenditure levels of $53.1 million in 2023 and $57.5 million in 2024, as approved in the Board's *2023-2025 DSM Plan* decision (M10473).

[347] Parties to the GRA Settlement Agreement accepted NS Power's request for the DCRR, with certain amendments:

> Implementation of the DSM Cost Recovery Rider (DSM Rider) as it was applied for, but with the amendment set out in Section 13 of NS Power's Rebuttal Evidence such that NS Power, rather than EfficiencyOne, will make the annual application for the DSM Rider to the Board and further amended to remove the last two bullets on page 8 of the DSM Rider, as committed to in the oral hearing and in Undertaking U-40. In addition, the DSM Rider charge will be incorporated within the class energy charges (i.e. not segregated on customer bills). For greater certainty, the DSM Rider's allocation of costs to customers shall be consistent with E1's approved 2023-2025 Application. For customers taking service in the Wholesale or Renewable to Retail markets, recovery of DSM costs will be through direct billing by NS Power to such customers.
>
> [Exhibit N-155, p. 6]

[348] The proposed DSM Cost Recovery Rider consists of two components:

1) The Program Cost Recovery (PCR) component, which includes all estimated costs for the upcoming calendar year for the DSM Plan that has been requested by the Franchise Holder and approved by the Board. The PCR is computed for each rate schedule using the cost allocation methodology set out in the tariff;

2) The Balance Adjustment (BA) component, which is the difference between the amount billed in the previously completed calendar year from the application of the PCR unit charges and the actual cost of the approved DSM during the same previously completed calendar year. In order to enable incorporation of a full year's actual results, the BA will address differences in the year that is 2 years prior to the current PCR year.

[349] The DCRR also requires that on or before October 1 of each year, NS Power will file its application for approval of the DSM cost recovery charges to be effective on the following January 1. The cost recovery components will be forward-looking based on projected costs for the upcoming year. The true-up component will reflect the difference between actual costs and billed amounts for prior year DSM activities.

[350] In closing submissions, the only dissenting opinion about the DSM Cost Recovery Rider was expressed by NRR:

> 76. NRR generally supports the DSM rider as set out in the Settlement Agreement, but challenges NSP's position that simply because there is no direct linkage to the changes in cost and revenue amounts since 2014 to annual class DSM programing approved by the Board, that the proposed calculation of DSM costs must be based on the 2014 cost of service to satisfy amendments to s 64A of the *PUA*.
>
> [NRR Closing Submission, pp. 14-15]

[351] Another related item identified in the Final Issues List was DSM true-up of prior period variances (see matter M07151). This issue focused on true-up of variances associated with the DSM programs for 2015, 2016-2018, and beyond, in view of the DCRR termination as of January 1, 2015. In its Reply Submission dated February 23, 2016 in that matter, NS Power stated:

> … NS Power proposes that DSM revenues be trued up against actuals in accordance with how the previous true-up mechanism worked under the DSM Cost Recovery Rider (DCRR). Under this scenario, NS Power would compare recoveries and costs on an annual basis and ensure that the amounts are tracked in order to be appropriately allocated at the next rate setting procedure.
>
> [M07151, NS Power Reply Submission, p. 4]
>
> NS Power notes that many of the cost allocation issues before the Board in this matter pertain to how DSM costs are divided amongst and collected from the various rate classes.
>
> The Company recommends as follows:
>
> …
>
> - NS Power does not have a strong preference as to which cost allocation methodology is utilized, however, based on the submissions from the parties, the "Traditional Approach" to DSM cost allocation and true-up should be implemented.
>
> - True ups will be tracked annually and affected into rates at the time of the subsequent GRA.
>
> [M07151, NS Power Reply Submission, p. 7]

[352] In its Decision in Matter M07151, the Board approved NS Power's proposal to annually track comparisons of DSM cost recoveries to DSM expenditures, and then to adjust any required variances during the next GRA.

[353] In his evidence in the current GRA, Mr. Drazen addressed this issue and noted the following NS Power IR responses:

> There is no true-up of DSM variances from budget recovered in customer rates. There is a true up of variances between budget and payments by NS Power to E1 between contract periods (i.e. variances across a contract period are rolled forward as adjustments to future contract period payments).
>
> [Exhibit N-41, NSPI (NSUARB) IR-185]
>
> NS Power has updated the schedule comparing actual DSM expenditures to the approved E1 DSM budget amounts to the end of 2021…NS Power does not consider this to be a comparison to recoveries as these amounts, in particular the annual DSM class-specific recovery amounts, were not established through the most recent GRA-vetted Cost of Service Study (2014) for the recovery of DSM costs and have not been updated annually since that time in accordance with the Board-approved DSM program spending.
>
> [Exhibit N-38, NSPI (IG) IR-40]

[354] Mr. Drazen recommended that NS Power be directed to provide the originally proposed intra-class true-up for the Board's consideration. In responding to this recommendation, NS Power's Rebuttal Evidence stated that the changes in cost and revenue amounts since 2014 have no direct linkage to the annual class DSM programming approved by the Board. NS Power also noted that the variances should be a measure of DSM program funding and the associated revenues assumed to have been built into rates, if this had been assessed and reset each year, but that was not done. In addition, NS Power expects the 2023 DSM Rider amounts will recognize past class variances in DSM program spending, as may be appropriate.

[355] In canvassing this issue, Board IR-1 to John Todd of Elenchus, consultant to EfficiencyOne, asked whether he considered that NS Power's "allocation tables" and "variance analysis", in response to IG/Dal IR-40 (Attachment 2 Confidential), constituted reasonable proxies for such "class specific recovery amounts" until they are reviewed in an updated Cost of Service Study. His response was:

> Elenchus considers that NS Power's "allocation tables" and "variance analysis," in response to IG/Dal IR-40 (Attachment 2 Confidential), constitute a conceptually reasonable approach to determining the "class-specific recovery amounts", however, a careful review and cleanup is required.
>
> …
>
> Elenchus is of the view that the details of the methodology that are embedded in the NSPI's model require careful review prior to accepting as appropriate any of the embedded assumptions that were not determined and approved for each year by the NSUARB.
>
> [Exhibit N-98, E1 (NSUARB) IR-1]

[356] This issue was not addressed in the GRA Settlement Agreement or in Closing Submissions.

7.7.1 Findings

[357] The Board accepts NS Power's proposal to segregate DSM costs from its revenue requirement to facilitate separate tracking and recovery under the DCRR. This approach, including the true-up mechanism, will improve transparency and efficiency in appropriately allocating costs among rate classes. Most parties accepted NS Power's proposal to implement a DCRR, if it agreed to incorporate certain amendments as stated in the GRA Settlement Agreement. Accordingly, the Board approves the DCRR as referenced in the GRA Settlement Agreement.

[358] Recognizing that this GRA decision is being released after the October 1 DCRR filing date noted in the tariff, NS Power is directed to file updated DCRR charges for 2023 within its compliance filing.

[359] As the issue of DSM true-up for prior period variances was not addressed in the GRA Settlement Agreement, the Board makes no determination at this time. The Board assumes that NS Power and stakeholders will continue to discuss this issue and

directs that an update on this matter be filed no later than the first application to adjust the DCRR approved in this decision.

7.8 Cost of Service Study and Line Loss Study

[360] The Board released its *2013 Cost of Service Study* (*COSS*) decision in March 2014, 2014 NSUARB 53 (M05473). NS Power applied the Board's findings from that decision in the cost of service methodology for the present GRA. In the GRA Settlement Agreement, the parties agreed to a process in which an updated COSS and a Line Loss Study will be completed prior to NS Power's next GRA or December 31, 2025, whichever is sooner:

> NS Power must file a Cost of Service Study and a Line Loss Study prior to filing its next GRA or December 31, 2025, whichever is sooner. NS Power will provide for stakeholder engagement in the scoping and review of initial results, which will include consideration of bundled and unbundled services in an integrated manner as referenced in the Board's decision at para. [42] in 2021 NSUARB 126, prior to filing the final Studies. Board approval for the use of those Studies should occur as a part of the next GRA proceeding. Costs associated with the production, stakeholder engagement, and filing of these Studies may be deferred by NS Power and, subject to Board approval, recovered through rates subsequent to NS Power's next general rate application.
>
> [Exhibit N-155, pp. 6-7]

[361] In this proceeding, several concerns were raised about NS Power's cost of service methodologies applied in this GRA. These concerns included the use of the minimum system study for the classification of distribution costs, the cost classification and allocation for generation and transmission using a base load power methodology inherent in the Load Factor/3 Coincident Peak (LF/3CP) method, and the sub-functionalization of distribution costs between the primary and secondary distribution systems.

[362] Resource Insight stated that the relevance of the LF/3CP method had waned as NS Power's generation and purchased power mix had changed and was in transition. It said other cost allocation methods should be considered due to factors such as increased use of the Maritime Link to access market energy, increased regional wind and solar penetration, grid-scale battery storage, increased reliance on purchased power agreements and increased investment intended to support electrification and distributed energy resources.

[363] The reference in the GRA Settlement Agreement to the Board's *BUTU* decision [2021 NSUARB 126] highlighted the concerns expressed by Mr. Athas, the SBA's consultant, and Darren Rainkie, Board Counsel's consultant, about the growing integration of bundled and unbundled services in the developing modern power system:

> [42] As noted above, Mr. Athas supported the use of embedded costs to establish pricing under the BUTU Tariff to provide for consistent pricing for the same regulated services. In his view, all customers receiving the same service should be treated equitably, "whether the customer (or customer class) receives only one service from the utility or all services in a bundled offering." He felt NS Power should include bundled and unbundled services in an integrated cost of service study to "minimize or eliminate the potential for cross subsidization." The Board agrees that there are aspects of the services that are similar, and it is attracted to Mr. Athas' suggestion that costs relating to bundled and unbundled services should be considered together in an integrated cost of service study where any appropriate differences in the services can be considered.
>
> [*BUTU* Decision, 2021 NSUARB 126]

[364] Later in the *BUTU* decision, the Board again highlighted the concerns expressed about the integration of bundled and unbundled services offered by a utility:

> [74] In his pre-filed evidence, Mr. Athas said all forward-looking utilities should recognize their role in providing regulated unbundled services will only grow and he urged the Board to consider the present application "in the context of developing a foundation for costing unbundled utility services that can be applied in future unbundled service pricing" (Exhibit N-15, p. 9). Mr. Athas agreed with the transition of the BUTU Tariff to embedded cost of service-based pricing to provide consistency with bundled service class customers, but expressed concerns with NS Power's dated cost of service study given changes that have taken place in the decade since the study was prepared. He also questioned whether the parties and the Board would consider the same cost allocation methodologies when viewing bundled and unbundled services together.

> [75] Board Counsel consultant, Darren Rainkie, shared Mr. Athas' view that the proper way of dealing with bundled and unbundled services is through a cost of service study. In his testimony at the hearing, he referenced the four "Ds" driving the current energy transition: decentralization, democratization, decarbonization, and digitalization. He said a cost allocation study recognizing the "new transitional world" in terms of the energy market would be the preferable way to deal with and balance rate-setting factors.
>
> [*BUTU* decision, 2021 NSUARB 126]

In the *BUTU* decision the Board shared the concerns of Mr. Athas and Mr. Rainkie about the COSS.

[365] In its Pre-filed Evidence, Resource Insight also had concerns about what it perceived as NS Power's failure to address an earlier Board directive around updates to its Line Loss Study. The CA's consultant stated that, without these updates, it is likely that the cost of service is inaccurately allocated among customer classes, resulting in some customer classes having rates that are unfairly high. NS Power responded that while the updated load research sample was used to allocate the class coincident demands in the COSS, the line loss estimates in the GRA remained consistent with past applications. The Utility agreed that further work was required to refine the class level line loss estimates, but that such data was not readily available until AMI was fully implemented with its customers. It said that it was premature to undertake the Board's directive until the data was available.

7.8.1 Findings

[366] The parties agreed through the GRA Settlement Agreement that both a COSS and Line Loss Study must now be completed before the next GRA or by December 31, 2025, whichever is sooner. The parties also agreed to a stakeholder engagement process for the scoping and review of initial results.

[367] The Board concurs that the COSS and Line Loss Study should be updated to reflect a number of developments impacting NS Power's system since the 2013 COSS, including the greater integration of wind and other renewables, the addition of gas fired generation, the phasing-out of coal fired generation, the use of grid-scale battery storage, the increased reliance on purchased power agreements, and the integration of bundled and unbundled services, among other issues. All other cost allocation methodologies should be reviewed for their continued relevance and application. The Board concludes that this provision of the GRA Settlement Agreement is appropriate and directs the process and timeline as agreed to by the parties. The Board directs that semi-annual progress reports must be filed with the Board starting January 31, 2024.

[368] As part of the proposed settlement for NS Power to complete the COSS and Line Loss Study, it was agreed, subject to Board approval, that the costs associated with the production, stakeholder engagement, and filing of these studies may be deferred by NS Power and recovered through rates after the next general rate application. The Board approves this deferral.

7.9 Accounting and Financial Matters

7.9.1 Materiality Thresholds

[369] In 2019 NS Power applied to the Board for revision of some of its accounting policies. As part of its review of the accounting policy changes, the Board reviewed NS Power's capitalization limits. In response, NS Power engaged KPMG to provide a jurisdictional scan related to its capitalization limits. In a letter dated October 9, 2020 (M09229), the Board directed NS Power as follows:

> The Board directs NS Power to propose revised thresholds that reflect either a fully analyzed administrative burden or that brings NS Power in line with the average of comparable utilities and provide a sensitivity analysis that demonstrates the impact of incorporating such results in the next rate case.

[370] In response to this directive, NS Power engaged KPMG to update its previously completed jurisdictional scan and included its evidence as Appendix 8F in the application. In its evidence, Grant Thornton concluded the following:

> Based on the updated jurisdictional scan, we believe NSPI has demonstrated they are in line with the average of comparable utilities and therefore recommend that the Board accept NSPI's position that no revision to the capitalization materiality thresholds included in Accounting Policy 1560A are necessary at this time.
>
> [Exhibit N-56, p. 80]

[371] Based on the analysis provided, the Board is satisfied that the materiality thresholds in place are in line with the average of comparable utilities and, therefore, appropriate.

7.9.2 Depreciation Study

[372] NS Power noted in its application that a depreciation study would typically precede or coincide with a GRA process. Prior to the current GRA, NS Power did not complete a depreciation study. NS Power stated the reason for this was the uncertainty surrounding the timing of retirement of the coal plants having such a material impact on depreciation rates. In response to the Board's IRs on the GRA Settlement Agreement, NS Power stated that it intends to file a depreciation study in advance of its next GRA and has proposed the use of the DDA to separately deal with the retirement of the coal plants. It further stated that the consultative process for the DDA will inform the scope of the depreciation study, including whether it will address the thermal assets.

[373] Grant Thornton stated in its evidence that it does not agree with NS Power's position to forego completion of a depreciation study on NS Power's asset pools not impacted by the retirement of the coal plants. In its Closing Submission, NRR requested that the Board order NS Power to complete a depreciation study.

[374] The Board agrees that a depreciation study is necessary and directs NS Power to file a depreciation study prior to its next GRA. The Board further directs NS Power to include the scope of the depreciation study as part of its DDA consultative process with stakeholders and the resulting report on that process.

7.9.3 Taxes

[375] In its evidence, Grant Thornton made the following conclusion and raised two issues with respect to NS Power's tax expense:

> Income tax expense for forecast 2021 and proposed 2022, 2023 and 2024 appear consistent with substantively enacted corporate income tax rates and forecast except in relation to the following two matters:
>
> • 2024 includes $5 million income tax expense that requires further examination to ascertain if the balance is an appropriate revenue requirement cost.
>
> • We identified a $35 million amount in rate base pertaining to a deferred income tax asset for non-capital losses potentially created by Part VI.1 tax deductions. We recommend that all activity related to Part VI.1 tax should be included in unregulated activities of NS Power and excluded from rate base.
>
> [Exhibit N-56, p. 49]

[376] NS Power, in its Rebuttal Evidence, explained that the $5 million expense highlighted by Grant Thornton was an adjustment required to account for a portion of the income tax loss that was unavailable to be carried back to prior years. In response to Undertaking U-13, NS Power further explained that the amount available to be carried

back was limited because the legal entity taxable income in the previous three years was lower than the taxable income on a regulated entity basis.

[377] The Board notes that, generally, the income tax impacts of all unregulated expenses should be segregated along with those unregulated expenses and should not, therefore, have any impact on test year forecasts. However, in the context of the test years in question, the government-imposed rate-cap results in such an adjustment being moot.

[378] In its Rebuttal Evidence, NS Power confirmed that the $35 million income tax asset noted above is, in fact, related to the Part VI.1 tax deductions, and explained that it is offset by a liability due to Emera such that there is no overall impact on rate base. NS Power also noted that it defers to the Board in relation to the treatment of the Part VI.1 tax transfer as unregulated.

[379] The Board agrees that since the Part VI.1 tax deductions and related transactions with Emera are unregulated activities, these items should be excluded from rate base and from the regulated financial statements of NS Power. The Board directs NS Power to exclude all Part VI.1 tax transactions and amounts from its regulated statements in the future, and to adjust for any amounts currently included in the regulated financial statements.

[380] Intervenors and the Board have expressed concern over NS Power's growing deferred income tax liability. This liability is due, in part, to timing differences associated with the accounting depreciation being different from the capital cost allowance for tax purposes. In response to Board IR-156, NS Power confirmed that it follows Accounting Policy 5900 by claiming sufficient capital cost allowance to minimize

cash taxes. Grant Thornton, in its evidence, noted this policy is prudent and almost universally applied. It also noted that this approach results in reduced current cost of service and increased future cost of service. Grant Thornton recommended the Board closely monitor the deferred income tax liability and its impact on cost of service through existing reporting processes. The Board agrees.

7.10 Amortization of Annapolis Tidal Generation Facility

[381] In its application, NS Power applied to create a regulatory asset for the Annapolis Tidal Generation Facility to recover its remaining net book value (NBV) over a 10-year period, representing an annual expense of $2.5 million. The plant is currently in rate base earning the allowed return and permitting NS Power to collect depreciation expense of about $800,000 per year through rates.

[382] In 2021, NS Power applied to the Board for approval to treat the plant as “Not Used and Not Useful” and proposed to amortize its undepreciated value and remaining Construction Work in Progress (CWIP) (in the total approximate amount of $27.7 million) over a 10-year period under Accounting Policy 6350. The Board concluded that NS Power had not shown that decommissioning the plant was the least cost option for ratepayers. Accordingly, the Board also found that it was premature to approve the proposed 10-year amortization under Accounting Policy 6350. The Board added that it would keep the matter in abeyance pending further information from NS Power, directing that NS Power provide a status update by January 31, 2023. The Board’s *Annapolis Tidal Accounting Treatment* decision, 2022 NSUARB 2 (M10013) was released January 13, 2022, two weeks before NS Power filed the current GRA.

[383] When asked in IRs why it had forecast the amortization of the Annapolis Tidal Generation Facility in the GRA as a proposed regulatory asset over a 10-year period, NS Power replied:

> NS Power produced the revenue requirement forecast before it received the January 13, 2022 decision from the NSUARB on the proposed accounting treatment. The revenue requirement forecast included the 10-year amortization period.
>
> …
>
> NS Power has reviewed the Decision and the matters raised by the Board regarding further analysis to demonstrate the least-cost option for the facility. NS Power will address these matters before submitting a new application to the NSUARB. The timing of such an application has not been determined.
>
> [Exhibit N-41, NSUARB IR-70]

[384] Grant Thornton expressed concern about NS Power's request in the GRA to include the Annapolis Tidal Generation Facility in its regulatory amortizations:

> NS Power has proposed to recover the retired assets associated with the Annapolis Tidal Generating Station with a remaining net book value excluding land of $25.4 million at December 31, 2021 (includes $23.5 million in PPE and $1.9 million in CWIP) over a ten-year period. This would result in a $2.5 million revenue impact annually over the test period of 2022F-2024F. In Matter M10013 (2022), the Board was unable to conclude if the Generating Station is not used or useful, and therefore the application has been held in abeyance. According to NS Power, the ten-year amortization proposed in this GRA was done so before Matter M10013 was held in abeyance. NS Power has stated they have reviewed the decision of M10013 (2022) and will address it with a new application to the Board. If the regulatory deferral and proposed amortization is not approved in the GRA, the impact on revenue requirement would be a reduction in amortization of $2.5 million each year, partially offset by higher depreciation, interest and equity costs due to the asset being included in property, plant and equipment instead of a regulatory asset.
>
> [Exhibit N-56, p. 51]

[385] However, in its response to an IR about the GRA Settlement Agreement, NS Power confirmed that it still intends to include the Annapolis Tidal Generation Facility in its forecast regulatory assets, for which NS Power seeks Board approval to recover financing costs at the Company's weighted average cost of capital [Exhibit N-156, Attachment 1].

7.10.1 Findings

[386] The Board recognizes that there was a short intervening two-week period in January 2022 between the Board's release of the *Annapolis Tidal Accounting Treatment* decision and the filing of NS Power's GRA. In those circumstances, it was not unreasonable for NS Power to assume that its application about the Annapolis Tidal plant might be approved by the Board and to prepare its GRA forecasts on that basis. However, ultimately, the Board did not approve that application and it is currently in abeyance. Despite the Board's ruling, NS Power continues to ask that the plant be included in its regulatory amortizations for the test years.

[387] In the Board's opinion, the inclusion of the Annapolis Tidal Generation Facility in NS Power's regulatory amortizations is in direct conflict with the Board's prior decision on that same point. A finding on that proposed accounting treatment is still premature while the matter is being held in abeyance. In the circumstances, the Board does not approve the component of the GRA Settlement Agreement that provides for the regulatory amortization of the Annapolis Tidal plant. The Board directs that the plant remain in property, plant and equipment.

7.11 Maritime Link Transmission – Capital Work Orders

[388] In this GRA, NS Power requested approval of four transmission capital projects (total cost of $44,687,437) related to the Maritime Link and the energy flows from the Muskrat Falls Generating Station. The application stated that those assets have been depreciating at shareholder expense since their in-service dates and are included in the GRA forecast at their net book value. In its May 3, 2022, response to Board IR-95, NS

Power provided annual depreciation amounts for each of these projects. The individual amounts shown below result in a total annual depreciation expense of $1,336,786:

- CI 43324 - L6513 Rebuild / Upgrade Line Terminals
  Cost $18,626,428; In-service date 2018/07; Annual Depreciation $717,755
- CI 43678 - Separate L8004/L7005 on Canso Crossing Double Circuit Tower
  Cost $20,387,278; In-service date 2018/07; Annual Depreciation $485,407
- CI 45066 - Upgrade L6511 and L7019 Thermal Rating
  Cost $2,691,017; In-service date 2018/01; Annual Depreciation $69,794
- CI 45067 - 67N Onslow 345 KV Node Swap
  Cost $2,982,714; In-service date 2018/01; Annual Depreciation $63,830

[389] Three of the four projects were initially submitted for approval in 2014 and 2015. Following a review of those applications, Board approval was not granted. CI 43678 was not previously submitted.

[390] Counsel for the Industrial Group and Dalhousie University canvassed the requirement for these transmission projects during the hearing, with reference to NSPML's initial application in the 2013 Maritime Link matter M05419. At that time, three of the transmission projects, estimated to cost $31.5 million, were identified as being required to allow Nalcor to deliver Nalcor Surplus Energy to the New England and New York markets. In that proceeding, it was noted that NS Power would incur capital, maintenance, and redispatch costs to enable Nalcor's wheeling requirement:

> As part of the exchange for 20 percent of the output from Muskrat Falls, Nalcor requires a transmission path through Nova Scotia and New Brunswick to allow Nalcor to deliver Nalcor Surplus Energy to the New England and New York markets.
>
> …
>
> …Based on NSTUA requirements and expected quantities of Nalcor Surplus Energy, NS Power is expected to incur capital upgrade, maintenance and redispatch costs associated with providing a path for the Nalcor Surplus Energy from the interconnection point with the Maritime Link at Woodbine through to the Nova Scotia / New Brunswick border.

…

Figure 8-1 Nova Scotia Power Network Upgrades[57]

NSPI Network Upgrades	Forecasted Investment					
	2013	2014	2015	2016	2017	Total
1 L-6513 Rebuild/Upgrade Line Terminals	1,610,000	8,168,000	322,000			10,100,000
2 Strait Crossing / Separate L-8004/L-7005	108,000	972,000	4,752,000	4,752,000	216,000	10,800,000
3 L-6511/L-6515/L-6552 Upgrades		1,060,000	9,540,000			10,600,000
	$1,718,000	$10,200,000	$14,614,000	$4,752,000	$216,000	$31,500,000

The cost to redispatch NS Power's fleet is also an estimate at this point and will depend on the amount and timing of the Nalcor Surplus Energy. Based on projections of Nalcor Surplus Energy, the estimated cost of redispatch is forecast to range from $6-8 million annually.

[Exhibit N-123, pp. 2-4]

[391] This was confirmed by NS Power during questioning by Ms. Rubin:

Q. So at the time, it was anticipated that Nova Scotia Power would need to undertake the following upgrades. And three projects are listed there, which, as you know, totalled about $31.5 million?

A. (MacDonald) Yes, that's what I see on the table at Figure 8.1.

Q. Okay. And those three projects are included among those that you have in fact filed for, plus one additional project, the CANSO Crossing Double Circuit?

A. (MacDonald) Yes.

Q. Okay. So at the time these three projects were, I guess, very preliminarily estimated at about $10 million each, and then in addition -- in addition to those capital costs, NSPI was expected to incur redispatch costs in range of 6 to $8 million?

A. (MacDonald) Yes, that's what I'm reading here in this paragraph.

Q. Okay. Plus operating cost?

A. Yes.

Q. And based on the projections of the Nalcor surplus energy that was being wheeled through Nova Scotia across these transmission paths, it was expected that fees from that wheeled-through energy, by Nalcor to third parties, would offset the capital expenditure, the redispatch cost, and the system maintenance cost; correct?

A. (MacDonald) Yes, that was part of it. And the "or" with that is, or benefits to the Nova Scotia system or Nova Scotia customers would otherwise be greater than that alternative you're speaking of.

[Transcript, September 12, 2022, pp. 270-272]

[392] As noted above, the primary reason for these projects was to facilitate Nalcor's intended energy export to third parties beyond Nova Scotia. They were not identified as a necessity for continuing to serve native load in Nova Scotia prior to the Maritime Link coming online. In its IR responses in matter M06525, NS Power stated:

> Response IR-5:
>
> (a) Associated with the Maritime Link project is the requirement to export 330 MW in summer and 150 MW in winter from Nova Scotia to New Brunswick. This requirement necessitates an increase of Onslow Import (ONI) level from 1,025 MW to 1,220 MW. With the increased transfer levels, the loss of the common breaker 67N-812, which takes out both 345 kV lines L-8002 and L-8003, would result in the remaining 230 kV lines being unable to support the post contingency load flow resulting in a system collapse.
>
> (b) This potential can start when the Maritime Link energy flowing into NS is 300 MW or above.
>
> (c) That potential does not exist prior to the Maritime Link, provided that ONI is below 1,025 MW.
>
> [M06525, Exhibit N-4, NSPI (NSUARB) IR-5]
>
> Response IR-6:
>
> (a) The additional power transfer capability will be necessary when the Maritime Link comes online in late 2017…
>
> <u>Prior to the Maritime Link coming online, the additional power transfer capability is not strictly needed to accommodate new load or generation</u>…[Emphasis added]
>
> [M06525, Exhibit N-4, NSPI (NSUARB) IR-6]

[393] The requirement for these transmission projects and their cost recovery were canvassed extensively by parties at the hearing. The following series of Board questions also explored the reasons for those projects:

> So the first question I want to ask is if the four Maritime Link Projects were not constructed, would the Nova Scotia Block be able to flow into Nova Scotia for use by Nova Scotia ratepayers?
>
> **A.** (MacDonald) For just the Nova Scotia Block to flow, my understanding is that not all aspects of the four projects would have been required, but that's one part of the overall transaction. So, no, not necessarily.
>
> **Q.** So no?

A. (MacDonald) Not for, in isolation, the Block, but I expect we should talk about more than that.

Q. When you say talk about more than that, what are you referring to?

A. (MacDonald) I'm referring to the other energy flows that were forecast whether to be left in province or for export, and the collection of related transition [transmission] projects, the four projects that go with all of that.

Q. Yeah, I guess my question is putting, you know, flows, energy flows, I guess, that were requested by Nalcor to flow through New Brunswick, were those four projects required -- if there was no requirement to flow this energy to New Brunswick, would those four projects have been required to accommodate flow of the Nova Scotia Block for use by Nova Scotia ratepayers.

A. (MacDonald) The projects are required for the flows into Nova Scotia beyond the Block…

…

Q. Those other energy flows are over and above the Nova Scotia Block.

A. (MacDonald) Yes.

Q. All right. And if I understand the Maritime Link Project correctly, at the time the Maritime Link was put into service, the intent was to retire Lingan 2.

A. (MacDonald) Yes.

Q. It hasn't quite worked out that way, but that was the intent. So the way I read that is it was sort of a like-for-like replacement and that, you know, the Maritime Link energy would provide a renewable source of energy that replaced coal-fired energy from Lingan 2.

A. (MacDonald) Right, which is why, in the situation where precisely Lingan 2 off and precisely Nova Scotia Block on, you could say that the transmission investments for that exact situation, but for also considering the rest of the energy flows, you could maybe in this -- I talked about this the other day, about the timing or how you might stage the work plan to line up when you would do those projects to do Block-plus. But the way it was done because of how the entirety of the transaction and the project was ultimately approved, and the economics of it taken together was that those projects were completed at the same time and then, as you alluded to, the block flowing or not and then the timing of Lingan 2 has been different, but to the benefit of Nova Scotia customers and the way the system can be staged to do many things now, including the flows of the Block, that's definitely a benefit to customers.

Q. When you talk about the other energy requirements over and above the Block, is that just strictly related to the energy flows that were expected to wheel through for Nalcor?

A. (MacDonald) No, I'm talking about the capability to keep larger flows in province.

Q. Keep larger flows from surplus energy, market-price energy?

A. (MacDonald) Yes.

Q. Over and above Nova Scotia Block.

A. (MacDonald) Yes. And perhaps the supplemental energy, although sometimes the labels escape me.

[Transcript, September 14, 2022, pp. 727-732]

[394] The capacity associated with the NS Block is 153 MW. Since the energy and capacity from the NS Block is intended to displace generation from Lingan Unit 2 (148 MW), thereby essentially maintaining equivalency on the provincial grid, the Board understands that the above reference to exporting 330 MW in summer and 150 MW in winter from Nova Scotia to New Brunswick is in addition to the NS Block.

[395] In its direct evidence, NS Power stated that OATT tariff revenues from wheeling Nalcor energy through Nova Scotia were expected to offset the cost of those capital projects:

> The submitted capital applications were not approved by the NSUARB at that time. In its reasoning the Board expressed similar comments to those noted in the 2014 ACE Plan proceeding. NS Power affirmed in those written hearing proceedings that the tariff revenues would likely offset the full cost of the transmission upgrades, and the Company would not seek to put costs into rate base in compliance with the Board's 2014 ACE Plan directive.
>
> With respect to the offsetting of capital costs by tariff revenues, NS Power provided the following in response to Board questions regarding CI 45067:
>
>> Consistent with the submissions during the Maritime Link hearings, the cost of these capital investments (i.e. annual financing, depreciation, operating costs, etc.) and redispatch requirements are expected to be offset by tariff revenue related to Nalcor energy transported across NS Power's transmission system to third parties over the term. The forecast tariff revenues will be applied to reduce the amount to be recovered from Nova Scotia Power's customer base and to reduce the associated rates developed through General Rate Applications.
>>
>> A potential exception is if it is determined to be in customers' interests for NS Power to acquire additional Nalcor energy (market energy), the tariff revenue recovered from Nalcor may be less than that included in the tariff and less than that applied for the purposes of developing general customer rates. Such decisions to purchase Nalcor energy will be tracked and take into account the foregone tariff revenue prior to a determination that acquisition of the energy is in the best interests of customers.

[Exhibit N-16, p. 65]

[396] Following-up on Ms. Rubin's questioning, Board Counsel sought clarification on how the transmission project costs would be offset if the OATT revenues received from Nalcor for energy transport across Nova Scotia were diminished due to NS Power retaining Nalcor surplus energy for use within Nova Scotia:

> **Q.** Okay. So the bottom line you're saying is the "or" piece that you mentioned the other day, which is that you're retaining the surplus energy, market energy, rather than shipping it through to New Brunswick will count for purposes of deciding whether it's revenue neutral to Nova Scotia Power's customers.
>
> **A.** (MacDonald) Yes, and that I would expect that as with any other review of how we dispatch the system, be that FAM or otherwise, that that has an ongoing process to test for that, and ---
>
> **Q.** Right.
>
> **A.** (MacDonald) --- that the transmission investments that we're talking about here, while to enable to path, also enable the way the energy will move around depending on the amount of market energy or surplus energy is being ---
>
> **Q.** Well ---
>
> **A.** (MacDonald) --- left to Nova Scotia at any given time.
>
> **Q.** But you stand by this evidence?
>
> **A.** (MacDonald) Yes.
>
> **Q.** And it will be up to the Board to decide after NSPI bills the shortfall on the tariff side to NSPML, for NSPML to then seek approval for that in its assessment and demonstrate the benefit to the Board?
>
> **A.** (MacDonald) Yeah…
>
> [Transcript, September 13, 2022, pp. 620-622]

[397] In Industrial Group and Dalhousie University IR-33, NS Power was asked to provide the monthly transmission tariff revenues from Nalcor for energy wheeled through Nova Scotia since the Maritime Link was placed in service. During the hearing, NS Power was asked to confirm, by way of an undertaking, that the monthly revenues provided in that IR response were in fact tariff revenues received from Nalcor for surplus energy wheeled through Nova Scotia. In its Undertaking U-3 response, NS Power stated:

> … This transmission service was not solely for Nalcor Surplus Energy being sold to third parties, but rather primarily for energy purchased from third parties and wheeled through Nova Scotia between the New Brunswick border and Newfoundland and Labrador.
>
> [Exhibit N-152, Undertaking U-3, pdf p. 8]

[398] NS Power's response to Industrial Group and Dalhousie University IR-33 also stated that tariff revenues for 2022, 2023 and 2024 were not included in any revenue assumptions for this GRA because it does not expect material tariff revenues going forward. NS Power said it intends to maximize purchases of available energy from Muskrat Falls, which means there will be less energy wheeled through Nova Scotia by Nalcor, and therefore, less OATT transmission revenue will be received. In that same IR response, NS Power stated that these additional energy purchases will create more value for NS Power's customers than would be created by flowing this energy through the province and collecting the tariff revenues.

[399] During the hearing, NS Power was also asked, by way of an undertaking, to provide an economic analysis to show that the forecast surplus energy purchases plus the OATT revenues over the test period would offset the related capital costs of the Maritime Link transmission projects. In its partially confidential response in U-64, NS Power provided results of a modeling analysis which compared costs assuming purchases of certain quantities of Nalcor surplus energy against the alternative of no Nalcor surplus energy being purchased. It stated:

> NS Power completed a Plexos run to compare the fuel refresh forecast to a scenario in which the Company did not have access to market-priced energy over the Maritime Link. The scenario in which NS Power did not have access to market-priced energy over the Maritime Link resulted in forecast greater fuel costs…
>
> [Exhibit N-152, Undertaking U-64, pdf p. 607]

7.11.1 Findings

[400] Having reviewed the current transmission capital project applications, along with related filings and transcripts, the Board's understanding continues to be that the primary reason for those projects is to enable Nalcor to transmit energy through Nova Scotia to third parties in other jurisdictions. They were not needed to accept the 153 MW NS Block, which is intended to displace similar capacity from Lingan Unit 2.

[401] The Board also notes NS Power's statements that it intends to maximize purchases of available energy from Muskrat Falls, which means that less transmission revenue will be received, but greater value may be created for customers. It is not clear whether that surplus energy purchase will be displacing energy currently generated by other Lingan units or other coal-fired generators. However, experience to date with receiving even the NS Block of energy has been poor. Ongoing delays with Nalcor's commissioning of the Labrador Island Link continue to highlight concerns about the value that might be created for Nova Scotia customers.

[402] It is incumbent upon the Board to highlight its concerns stated in earlier decisions. In its *2017 ML Interim Assessment* decision [2017 NSUARB 149], the Board stated:

> [153] NSPML indicated that it wants to have the Final Assessment hearing during 2018. The Board is not prepared to hold the Final Assessment hearing until it knows that the NS Block is being delivered in accordance with the original bargain. This will enable the Board to reserve whatever regulatory options may be available to it in the event of further unfortunate news.
>
> …
>
> [155] However, the Board is not prepared to approve the final assessment until it is confident the ratepayers will get what they bargained for - the NS Block, Supplemental Energy and Nalcor Market-priced Energy.

[403] That position was reiterated in the *2019 ML Interim Assessment* decision [2019 NSUARB 156], the *Final Project Costs* decision [2022 NSUARB 18] (M10206), and in the recent *2023 ML Cost Assessment* decision [2022 NSUARB 191] (M10708).

[404] In the *Final Project Costs* decision, and repeated in the *2023 ML Cost Assessment* decision, the Board also stated:

> [19] As of the date of the hearing only approximately 19% of the NS Block and Supplemental Energy had been delivered for the period commencing August 15 to the end of November 2021.
>
> [20] …The Board has noted in the past that NSPML and NS Power have over-promised and underdelivered when they describe benefits from the Maritime Link. In the 2017 interim assessment hearing, when NSPML was arguing that the Maritime Link was used and useful even in the absence of NS Block, NSPML and NS Power stated that energy and other benefits in excess of $120 million in 2018 and 2019 were expected. In fact, those benefits were less than $5 million per year in each of those years.
>
> [21] One might ask why the Board set these conditions in the *2017 Decision* and repeated them in every interim assessment since. That turns on the phrase "this will enable the Board to reserve whatever regulatory options may be available to it in the event of further unfortunate news".
>
> [22] The Board was preserving, for the benefit of ratepayers, the full measure of its regulatory authority to deal with what that "unfortunate news" might turn out to be.
>
> [*Final Project Costs* decision, pp. 13-14]

[405] The Board concludes that it must continue to "reserve whatever regulatory options may be available to it in the event of further unfortunate news". Therefore, the Board defers allowing the inclusion of the above-mentioned four transmission projects into rate base until NS Power can demonstrate that, for a minimum of four consecutive quarters:

(a) the wheeling tariff revenue;

(b) the net economic value of NS Power purchases of additional Nalcor surplus energy (based on actual results following the methodology used in Undertaking U-64); or

(c) a combination of wheeling tariff revenue and the economic value of purchased Nalcor surplus energy,

is at least equal to the combination of depreciation, financing costs, operating costs, and re-dispatch costs. If this threshold test has not been met by NS Power's next GRA, NS Power may seek the Board's approval to include the transmission projects in its rate base if it can demonstrate that there is justification for doing so.

7.12 Bill payment, credit and collection matters

[406] In the Board's *2013-2014 GRA* decision, [2012 NSUARB 227] (M04972), the Affordable Energy Coalition, the CA and NS Power reached a settlement agreement establishing a consultative process "with a view to resolving bill payment, credit and collection matters affecting low-income residential customers". The Board described this as a positive development and endorsed the agreement, incorporating its terms into its final Order.

[407] The Board received a report in 2013 following the consultative process and incorporated its recommendations into NS Power's rules and regulations. In its Opening Statement in the present GRA, the Affordable Energy Coalition noted that there has been no formal evaluation of those changes. In both its Opening Statement and its Closing Submission, it requested a process to evaluate the changes approved in 2013, to examine if further changes are needed, and to "establish a systematic evaluation methodology". The Affordable Energy Coalition added that affordability most affects low- and modest-income households:

> …They are the ones who face disconnection most often and who most often must choose among different necessities when faced with high energy costs. This is more acutely true today due to recent fossil fuel price volatility and current high fuel prices.
>
> [Exhibit N-105, p. 2]

[408] In its Closing Submission, the Affordable Energy Coalition filed a letter from NS Power dated November 24, 2022, confirming the Utility's commitment to engage with the Affordable Energy Coalition and CA to review the outcomes related to credit and collections from the 2013 changes to NS Power's Regulations for the benefit of low-income residential customers, and to consider any additional changes that could assist low-income households. In its Closing Submissions, the CA confirmed he would participate in such discussions.

[409] The Affordable Energy Coalition added that this review should be undertaken with the explicit direction of the Board with a report back to the Board for its consideration and approval of any changes it deems beneficial.

7.12.1 Findings

[410] As noted in the Board's letter finalizing the Issues List for this matter, affordability is one of many issues to consider when setting rates that are just and reasonable. Indeed, the Board is mindful that electricity rates are already challenging for many and that Nova Scotia is reported to have one of the highest rates of energy poverty in the country. In its *2013-2014 GRA* decision, the Board noted it "receives literally hundreds of letters and emails a year from consumers who are struggling to pay their power bills and at the same time manage the cost of home heating, medication, groceries, etc." [para. 110]. The Board also received many letters of comment in the present matter outlining the impact of power rates on low- and fixed-income customers.

[411] The proposed review and consultative process has the commitment of NS Power, the Affordable Energy Coalition and the CA. The Board is pleased to endorse this initiative aimed at lessening the impact of power rates on low- and fixed-income residential customers. Accordingly, the Board directs that the three parties engage in a review process to evaluate the impact of the changes approved in 2013, to examine if further changes are needed, and to establish a systematic evaluation methodology that can be applied to future changes to NS Power's Regulations. The Board directs that a report be provided by April 30, 2023.

7.13 Miscellaneous charges and regulations

7.13.1 Customer Charges

[412] In its application, NS Power identified a significant increase to the customer charges in the Domestic Class and the Small General Class tariffs based on its cost of service:

Figure 12-2: 2022-2024 Customer Charges Based on Cost of Service

Customer Charge	Units	Current 2022	Proposed for 2022	Proposed for 2023	Proposed for 2024
Domestic Service Tariff	$/mo.	10.83	21.75	21.95	21.99
Domestic Service Time-of-Day Tariff	$/mo.	18.82	21.75	21.95	21.99
Small General Tariff	$/mo.	12.65	24.45	24.15	24.07

[Exhibit N-16, p. 99]

[413] The Utility proposed to phase-in the increase over the test years to the full amount in the 2024 test year.

[414] The customer charges have not changed since the early 2000s. These charges are intended to recover retail costs to serve a customer that are largely

independent of consumption levels, such as metering, customer care and billing costs, and a customer-related portion of the distribution system costs. Concentric (Dane and Rimal), NS Power's consultants, noted that since these costs are classified as being customer-related within the COSS, it is appropriate to recover them through the customer charges [see: Exhibit N-17, Appendix 12A, p. 26]. With the passage of about two decades, NS Power stated the customer charges now fall significantly short of the costs these charges are intended to recover. For the Domestic Charge, NS Power stated that the current $10.83/month customer charge recovers less than half of the costs that should be recovered in this charge and is among the lowest in Canada (and is less than half of the charge in the other Maritime provinces). Accordingly, NS Power proposed to phase-in the increases to the customer charges.

[415] Further, NS Power noted that, applying the updated COSS, the observed price gap between the current customer charges and the proposed charges results in cross-subsidization across customer classes and causes inflated volumetric class energy charges:

- The under-recovery of fixed customer costs in the Customer Charge means these costs are being recovered in the inflated volumetric class energy charges. At a time when customers are making investment decisions in alternative energy sources based on the energy price of the Company's bundled service offerings, which are largely composed of embedded fixed costs that do not change with sales volume, this situation is contributing to cost transfers occurring within classes and will result in uneconomic decisions for participating and non-participating customers.

[Exhibit N-16, p. 98]

[416] It is important to note that the Domestic and Small General classes have customer charges, but do not have demand charges. The remaining distribution, transmission and generation costs are recovered through the Domestic and Small General class energy charges. NS Power noted that the increases in the revenue from

the customer charges will place downward pressure on the class energy charges. For example, the increase from $10.83/month to the proposed $21.99/month in the 2024 Domestic Class customer charge would reduce the energy charge in this class by approximately 1.4 cents/kWh. The impact of these customer charge increases will differ according to customer consumption levels. Thus, customers with higher loads for whom the customer charge makes up a smaller portion of their bill will experience a smaller increase in percentage terms.

[417] Resource Insight had concerns about the proposed customer charge increases. As noted earlier in this decision, they had concerns about the “minimum system” methodology employed by NS Power under the COSS to classify distribution poles and wires costs attributable to customers and among the customer classes. They recommended that the Board direct NS Power to prepare a new COSS before applying changes to the customer charges.

[418] Ms. Whited, of Synapse, also had concerns about the proposed increases. Like Resource Insight, she also focused on customer impacts across different usage and income levels and the view that higher energy charges promote conservation. She stated the proposed increases to the customer charges would dampen customer incentives to conserve energy and invest in energy efficient technologies, while potentially also harming low-income customers. In response to NS Power’s assertion that rate design should support beneficial electrification on the system, she said this would be better addressed through dedicated electrification rates, rather than significantly increasing customer charges.

[419] However, in the GRA Settlement Agreement, the parties agreed to an increase to the customer charges, but at a 25% reduction to the originally proposed increase in the cost of service rate for 2023, with no phase-in:

> As applied for, but at the 2023 customer charges amount with an agreed to reduction of 25 percent of the proposed increase and no-phase in given there will only be a one-time non-fuel/non-DSM rate increase. (Per Figure 12-2, page 99 of Direct Evidence but with 25 percent reduction to the proposed increase: Domestic Tariffs $19.17/month; Small General $21.28/month.)
>
> [Exhibit N-155, p. 5]

[420] In his Closing Submissions, the CA noted that an important concession by NS Power on this point was that the Utility committed to perform an updated COSS, which will support a fully informed customer charge.

[421] However, NRR opposed any increase to the customer charge:

> 82. NRR opposes any increase to Customer Charges. The imposition of a fixed cost increase will disproportionately impact families with low monthly bills, including renters, as well as ratepayers who choose to invest in energy efficiency or solar power and should expect relief from power charges as a reward for their efforts.
>
> 83. The evidence of Chernick and Wilson explained that the customer charge is properly intended to collect the actual cost to serve a minimum usage customer, and that NSP's proposed increase and its justifications for it should not be accepted.
>
> …
>
> 85. Although the Settlement Agreement notes that the rates agreed between NSP and certain intervenors is 25% less than requested in the Application, NRR asserts that any increase in customer charges is unreasonable for the reasons discussed by Chernick and Wilson.
>
> [NRR Closing Submissions, p. 16]

[422] NS Power challenged NRR's submission:

> …the change in the Customer Charge will benefit families with high monthly bills and will incent those that possess efficiency products like heat pumps to utilize them, and for those that do not possess them, to make the switch. Given the Province's recent announcement regarding the funding of heat pumps for low-income Nova Scotians, it would have been expected that NRR was in favor of the Customer Charge increase, as this change will result in the heat pumps being cheaper to operate given the lowering effect of the increased Customer Charge on the Energy Charge.
>
> If the intended implication in NRR's argument is that customers with low monthly bills are low-income customers, the evidence on the record does not support such a contention. In

> fact, this proposition has been specifically rebutted by Concentric in its evidence demonstrating that research has indicated that the usage pattern of low-income and non-low-income customers are similar. In addition to this, one of the Letters of Comment received by the Board in this proceeding was from the Antigonish Emergency Fuel Fund Society (AEFFS), a registered charity with a mandate to support individuals and families in the Antigonish Town and County who have difficulty paying for winter heat because of inadequate incomes. In its letter, the AEFFS states: “It is worth noting that 60% of all clients use electricity as their primary source of winter heat.” This means that 60 percent of the individuals and families represented by the AEFFS are high-volume users of electricity and would benefit from the increase in the Customer Charge, given its decreasing effect on the volumetric Energy Charge.
>
> [NS Power Reply Submission, p. 20]

[423] In NS Power’s Rebuttal Evidence, Concentric (Dane and Rimal) described how some low and high-income customers differed in their energy usage:

> … some low-income customers live in older, poorly insulated houses that consume more energy. In addition, low-income customers will be less able to afford energy efficient appliances as compared to non-low-income customers. Conversely, some high-income customers could potentially be low users. For example, net metering customers, i.e., customer that own their own generation resources, are likely to be low users. In addition, high-income users are more likely to own vacation homes and potentially have lower usage, especially if the property is not occupied throughout the year.
>
> [Exhibit N-102, Appendix A, p. 8]

7.13.1.1 Findings

[424] The Board finds that it is reasonable for the customer charges for the Domestic Class and Small General Class tariffs to be updated to reflect the current COSS. In addition to representing customer-related costs more accurately, this will also avoid undue cross-subsidization across customer classes. While the Board is mindful that there remain questions about the current COSS, these issues will be addressed as the COSS is updated before the next GRA, as noted elsewhere in this decision.

[425] Further, the Board accepts NS Power’s expert evidence that these increases to the customer charges will not disproportionately impact lower income customers. Those who use higher than average amounts of power, will see a corresponding decrease in their energy charges. Concentric noted from their research

that lower income customers are just as likely to be high use customers as customers with higher incomes. Indeed, the Board notes the above comments of the Antigonish Emergency Fuel Fund Society to the effect that 60% of its clients use electricity as their primary source of winter heat. For that majority, the increased customer charges will lower their energy charges.

[426] Taking into account all of the above, the Board approves the customer charge increases outlined in the GRA Settlement Agreement.

7.13.2 AMI Opt-Out Fee

[427] In its application, NS Power requested the following regarding meter reading:

1. Approval of NS Power's proposed monthly charge for providing non-standard meter service, at $3.67 per month for the following rate classes: Domestic Service, Domestic Service Time of Day, and Small General.

2. Approval of NS Power's proposed monthly charge for providing non-standard meter service, at $22.01 per month for the following rate classes: General, Large General, Small Industrial, Medium Industrial, Large Industrial, and the Municipal Tariff.

3. Approval of revisions to Regulation 7.1 (Schedule of Charges), and 5.1 (Meter Reading) as reflected in the attached in PR-03.

4. Approval to limit determination of the 2 percent threshold in Performance Standard 11 to customers with AMI meters.

[Exhibit N-16, p. 117]

[428] The assumptions used in determining those proposed fees were provided in Figure 12-10 as shown below:

Figure 12-10: AMI Opt-Out Model Assumptions

Opt-Out Charge Assumptions	
Customer Opt-Out %	3%
Opt-Out Total Customer	14,415
Total Meter Reads Per Year	29,904
Time Required (Hours)	5,417
Expected Average Cost 2022-2024	
Costs (In Millions $)	
Total O&M	$0.6
Depreciation, Carrying Costs, Tax	$0.1
Total Annual Revenue Requirement (In Millions $)	**$0.7**
Monthly Charge (Former Bi-Monthly Read Customers, now Semi-Annual Read)	**$3.67**
Monthly Charge (Monthly Read Customers)	**$22.01**

[429] The Board notes that these calculations are based on a customer opt-out rate of 3%, which is higher than the 2% assumed in the AMI capital expenditure application (M08349). A more detailed cost breakdown is provided in Exhibit N-27, PR-02, Attachment 2, which shows the following projections for the former bi-monthly and monthly read customers:

Year	Bi-monthly	Monthly	Annual Readings	Annual Cost
2022	$3.07	$18.44	40,461	$746,186
2023	$3.47	$20.82	30,795	$641,158
2024	$3.66	$21.99	26,725	$587,571

[430] In matter M08349, the issue of reducing or eliminating a potential opt-out fee was raised. Possible options included customers sending their meter readings to NS Power, either by postcard or electronically. Such provisions are available under existing Regulations. This issue was again explored in the current GRA via IRs and in the hearing:

Q. (Outhouse) And in Board IR-190, and there's no need to bring it up, NSPI was asked to:

> …provide any analysis undertaken that might eliminate or minimize [the] opt-out fees by enabling customers to submit photo, email, or postcard readings in place of [actual] meter readings.

And Nova Scotia Power's response was that, "No such analysis was undertaken."

Is that still true? No analysis has been undertaken in that regard?

…

A. (Willett) Yes, that's correct. And there's a listing below that ---

Q. Yes.

A. (Willett) --- for -- that explains the reasons.

Mr. Outhouse: If you could just scroll down?

Mr. Willett: Yeah.

Mr. Outhouse: Thank you.

Mr. Willett: So with moving to two reads per year, there is some requirements by the company to ensure that we are charging customers an accurate bill. There is some concerns with having postcard reads, which are listed in the IR response, and with having two reads per year, and having one or both of those as a postcard read, the company has expressed the reasons that would be of concern withing [sic] this response.

BY MR. OUTHOUSE:

Q. Your first answer is that:

> Per Regulation 5.1, postcard reads are an exception-based process for obtaining meter reads to be used when [Nova Scotia] Power is unable to obtain an on-site reading.

A. (Willett) That's what the response says. Correct.

Q. It's my understanding that there's certainly that exception in 5.1, but 5.1 also has a provision for postcard meter readings in rural areas and states:

> Where electric service is supplied to a Customer in a rural area, the Company may adopt a post card meter reading system of monthly or bi-monthly meter reading.

Isn't that the case?

A. (Drover) That is the case. However, that works in a situation where we're reading six times a year. It definitely becomes more complicated when we're only reading twice a year in terms of getting that true read that Mr. Willett mentioned.

Q. Regulation 5.1 also states, in regards to the postcard readings:

> The Customer shall record on the postcard the reading showing on the meter as of the reading date and shall immediately return the card to the Company. In these circumstances, the Company may consider postcard meter reading to be actual meter readings.

A. (Drover) That is true; however, I think it's important to point out that with AMI meters, they are more complicated to read than the traditional meters that we have. They cycle through various forms of information and to get the exact read of what consumption is, can be challenging.

Q. Sorry. Did you say AMI meters or non-AMI meters?

A. (Drover) Both, to be honest.

So the traditional analog meters are more complicated. Even the new meters for opt-out will be the AMI meters with the smarts turned off. The new meters are digital and cycle through.

So over time, it will become more complicated.

[Transcript, September 21, 2022, pp. 1948-1952]

[431] In Exhibit N-37 of matter M08349, NS Power provided an estimated total annual opt-out cost of $1,536,703. Board IR-3 [Exhibit N-37] asked for a calculation of the monthly amount that would be applied to each customer if the total annual cost remained with the total customer base. NS Power's response was $0.25 per month, under a customer base of 506,965. The current GRA, in PR-02 Attachment 2, shows a total estimated 2022 opt-out meter reading cost of $746,186 with a customer base of 522,142. Using simple math, this translates to a monthly customer amount of $0.12.

[432] The economic analysis provided with the AMI capital application (M08349) included a forecasted Meter Reading and Field Work Reduction cost savings totalling a present value of $56.8 million over the life of the project. Board IR-3 in Exhibit N-37 asked NS Power to provide the monthly cost reduction per customer resulting from the meter reading savings. In its response, NS Power stated that it did not do that calculation:

The AMI investment forecast savings and costs vary significantly across the project life. Collectively they constitute a relatively small portion of NS Power's annual revenue requirement approved for recovery from customers through customer rates. Consistent with this, the Company has not calculated a monthly cost reduction per customer resulting from the AMI meter reading savings.

[M08349, Exhibit N-37, Board IR-3]

7.13.2.1 Findings

[433] In considering NS Power's requested opt-out fee, the Board questions whether all reasonable options have been explored to minimize or eliminate the proposed fee. It is clear from NS Power's responses to IRs and under cross-examination that significant gaps exist in its analysis.

[434] For example, Regulation 5.1 clearly enables customers to submit meter readings via postcard, and "the Company may consider postcard meter reading to be actual meter readings". In questioning by Board Counsel, Mr. Drover stated "That is true", but asserted that reading the AMI meters is more complicated than reading the traditional meters, since they cycle through various forms of information so it can be challenging to get the exact consumption reading.

[435] Despite Mr. Drover stating that analog meters are complicated, provisions in Regulation 5.1 allow customers to take their own meter readings and send them to NS Power. In fact, NS Power's website includes a page titled "Send Your Meter Read", with an illustration on how to read the analog meter and an online form to submit the meter and account information. It is the Board's view that similar instructions can be developed for customers to read their digital meters and submit that information electronically or otherwise.

[436] In considering the requirement for an opt-out fee, the Board notes that customers who opt-out of the smart meter program will still be paying for that capital project through costs that are embedded in rates. Furthermore, the Board understands that many of the opt-out customers have done so due to their concerns about the health impact, whether proven or not, while customers on fixed- or low-income raised different concerns.

[437] Upon consideration of this issue, the Board is not persuaded that the amount of the proposed opt-out fee, or the need for a fee, has been fully explored or justified. It is incumbent upon NS Power to provide its customers with flexible options which could minimize the energy cost burden. That flexibility could include monthly, bi-monthly, semi-annual, or some other schedule of meter readings suitable for its customers.

[438] Accordingly, the Board does not approve the proposed opt-out fees at this time. NS Power may seek approval at a later time, after it has acquired actual experience with opt-out costs and has clearly demonstrated its experience with flexible customer options.

[439] Recognizing that current Regulations require monthly or bi-monthly meter readings, the Board will consider future amendments as may be appropriate.

[440] Regarding NS Power's request for approval to limit determination of the two percent threshold in Performance Standard 11 to customers with AMI meters, the Board considers that request to be premature. At this time, there is uncertainty with the number of meter readings that will be taken per year at each customer location, as well as uncertainty with what constitutes an estimated reading.

7.13.3 Large Industrial Tariff

[441] Two elements of the Large Industrial Tariff (the Interruptible Rider and the Distribution Adder) were canvassed in the evidence and addressed in the GRA Settlement Agreement [see: Exhibit N-26, PR-01 Attachment 1, pp. 35-40].

[442] The Large Industrial Interruptible Rider (LIIR) includes a credit to the electricity cost for LIIR customers who agree to accept non-firm service. The credit amount is applied to Billed Demand and is calculated based on the avoided cost of a combustion turbine, but the current credit rate (i.e., $3.43/kVA/month of billed demand) has not changed since 1996. NS Power updated the credit amount in this GRA based on current costs. The credit was proposed to change over the test years to the following amounts: $7.408/kVA/month in 2022, $7.486/kVA/month in 2023 and $7.263/kVA/month in 2024.

[443] The tariff also includes a new Distribution Adder. This charge applies to customers connected at the distribution level. In the application, the Adder increases over the test years to the following amounts: $1.570/kVA/month in 2022, $1.632/kVA/month in 2023 and $1.788/kVA/month in 2024.

[444] In the GRA Settlement Agreement, the parties agreed that the 2023 interruptible credit amount of $7.486/kVA should apply for the test years. However, they also agreed that the interruptible credit will be reviewed in the next COSS. For the Distribution Adder, the parties also agreed that the 2023 amount of $1.632/kVA should apply for the test years.

7.13.3.1 Findings

[445] The Board is satisfied that the interruptible credit should be updated because it was based on 1996 avoided costs of running a combustion turbine. The Board accepts the new calculated amount as reasonable and appropriate. As noted, the credit

will be reviewed in the next COSS. The Board also approves the addition of the new Distribution Adder and the amount as agreed to by the parties.

7.13.4 Pole Attachment Fees

[446] In its application, NS Power requested approval of an increase in the rate it charges to telecommunications carriers to attach their equipment to poles owned by NS Power (pole attachment fee). The original proposed increase represented an almost threefold jump from the current $14.15 to $37.71 per year. Various telecommunication carriers intervened in the GRA and filed evidence opposing the proposed increase, including Eastlink, Rogers and Xplore. A number of IRs were also exchanged among the parties and Rebuttal Evidence was filed. Among other issues, the telecommunications carriers identified their concerns about various assumptions used by NS Power in the calculation of the pole attachment fee.

[447] On September 16, 2022, NS Power filed a Settlement Agreement with the Board proposing a revised pole attachment fee, executed by NS Power, Eastlink, Rogers, and Xplore [Exhibit N-138]. The parties requested approval of the new proposed pole attachment fee set out as follows:

> 1. The Parties have agreed to a pole attachment rate effective the date of approval by the Board of this Settlement Agreement of $22/per pole/per year, with the rate to be increased by 2% on each of January 1, 2023 and January 1, 2024.
>
> [Exhibit N-138, p. 1]

[448] No other party in the GRA opposed the Settlement Agreement reached by NS Power with the telecommunication carriers. Indeed, in the comprehensive GRA Settlement Agreement, the parties expressly supported the terms of the pole attachment fee settlement.

[449] At the hearing, the Board asked NS Power to file an undertaking setting out the various assumptions considered by the Utility to determine that the pole attachment fee settlement was "just and reasonable" in terms of the components making up the fee to be charged to the users. NS Power noted that the reduced pole attachment fee would have an impact of about $3 million on its revenue requirement, compared to the original proposal. In response, NS Power filed Undertaking U-49 setting out its assumptions about the various components of the calculation of the fee.

[450] After the Board's request for the Undertaking, Mr. Grant noted that the Settlement Agreement represented a negotiated compromise on a variety of the elements of the fee. Thus, the assumptions made by his clients to reach the settlement on the fee itself may not be the same as those made by NS Power. While he submitted that the agreement represented a just and reasonable resolution of the issues and should be approved, Mr. Grant said in future proceedings all parties should be free to make submissions on any aspect of the pole attachment fee. Accordingly, his client carriers and NS Power proposed the following stipulation for the Board's consideration of the Settlement Agreement on this matter:

> NSPI and the carrier group negotiated the Settlement Agreement, Exhibit N-138, Pole Attachment Fee, as a total rate. It arrived at the $22 per pole as a compromise of their respective positions. The parties did not negotiate or agree upon the cost-of-service components to justify the $22 compromise rate. For example, there was no agreement on the appropriate pole attachment ratio. [Undertaking] U-49 therefore would represent NSPI's view of the - - of a cost-of-service justification for the Settlement Agreement rate of $22.
>
> [Transcript, September 21, 2022, pp. 2131-2132]

[451] In their Closing Brief, Mr. Grant and Ms. Milton submitted that the pole attachment fee set out in the Settlement Agreement should be approved by the Board:

> 21. In the present proceeding, NSPI and the Carrier Group have engaged extensively and intensively in the prehearing procedures to examine and test the evidence regarding the Pole Attachment Fee. Other parties have had similar opportunities. NSPI and the Carrier Group have succeeded in reaching a settlement agreement that reflects a

> compromise of their positions based upon their evidence. We submit the Settlement Agreement is properly supported. It is an outcome that was within the range of reasonable outcomes the Board could have reached on the evidence and, particularly in the absence of any opposition, represents a success of the regulatory process.
>
> 22. In its initial evidence in this proceeding, NSPI requested an increase in its Pole Attachment Fee from $14.14 to $37.71. The Carrier Group provided detailed evidence recommending a Pole Attachment Fee of between $14.90 and $19.27.
>
> …
>
> 25. The settlement rate is a compromise and is not based on agreement on specific cost inputs to the Pole Attachment Fee. NSPI has submitted a cost of service justification for a pole attachment rate of $21.81. While the Carrier Group does not agree with some of the cost of service inputs used by NSPI, including use of a pole attachment ratio of less than 2, the Carrier Group believes that the $22 rate represents a reasonable compromise based on the application of the same methodology established in the 2002 Decision using available cost of service information. The $22 rate is also a significant increase in the Pole Attachment Fee, resulting in incremental revenue to NSPI at no additional cost. [Emphasis added]
>
> [Eastlink/Rogers/Xplore Closing Brief, pp. 5-7]

7.13.4.1 Findings

[452] Earlier in this decision, the Board outlined the principles it applies in its review of settlement agreements. Those principles apply equally to the Board's review of the Settlement Agreement about the pole attachment fee. The agreement garnered the support of all parties directly impacted by the pole attachment fee and represents an all-encompassing resolution of the various issues, in the form of a proposed fee, raised by the telecommunications carriers.

[453] The Board observes that no other party in this matter challenged the Settlement Agreement, including the revised pole attachment fee. The current fee has been in effect since 2002 and it is appropriate that the inputs to the calculation be updated, at least to the extent that it informs the range of possible outcomes for the fee. The Board is also satisfied that, considered as a whole, the revised pole attachment fee represents a fair and reasonable estimate of what the amount should be, taking into account the

various issues which were in dispute between NS Power and the pole attachment customers.

[454] Having reviewed the Settlement Agreement about the pole attachment fee, and the submissions, the Board finds that the revised pole attachment fee is just and reasonable. The Board approves the pole attachment fee of $22/per pole/per year, with the rate to be increased by 2% on each of January 1, 2023, and January 1, 2024. The adjusted rates for each of the test years are to be confirmed in the compliance filing.

7.13.5 Open Access Transmission Tariff Charges

[455] In this GRA, NS Power is requesting approval of the revenue requirement and updated prices for services offered under the OATT. The OATT includes terms, conditions and rates for Transmission Services and Ancillary Services, as well as service and operating agreements under which service will be provided, and the Standards of Conduct which govern the treatment of transmission system and market information within NS Power.

[456] Parties to the GRA Settlement Agreement have agreed to the following terms regarding the OATT:

> …the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum increase of 1.8% in 2023 and 0% in 2024. With respect to the CBAS recommendations proposed by WKM Energy Consultants, the parties agree that these issues will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on these issues, following which NS Power and other parties as they see fit will have the opportunity to file a reply.
>
> [Exhibit N-155, p. 6]

[457] In their Closing Submission, the MEUs noted their support for Board approval of the GRA Settlement Agreement but also sought Board approval of the

Capacity Based Ancillary Services (CBAS) recommendations proposed by its consultant, Mr. Marshall:

> … As a signatory to the Settlement Agreement, the MEUs support the Board's approval of the Settlement Agreement as filed. The following points in the Settlement Agreement are critical from the perspective of the MEUs:
>
> - Confirmation that the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum of 1.8% in 2023 and 0% in 2024;
>
> …
>
> Since these issues are of significant importance to the MEUs and have long-term implications for the rates to be charged as part of the competitive wholesale market in Nova Scotia, the MEUs sought and obtained agreement from all signatories to the Settlement Agreement that the Backup/Top-up ("BUTU") GHG credit as proposed by Mr. Dominie and the Capacity Based Ancillary Services ("CBAS") recommendations proposed by Mr. Marshall would be left to the Board's determination in this proceeding following closing argument and reply.
>
> [MEUs Closing Submission, pp. 1-2]

7.13.5.1 Findings

[458] The Board approves capping NS Power's OATT rates at a maximum increase of 1.8% in 2023 and 0% in 2024 as described in the GRA Settlement Agreement.

7.13.6 Capacity Based Ancillary Services

[459] Ancillary Services are the support services that are required to enable the Transmission System to transmit energy while maintaining reliable operation of the system. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller, to services that are necessary to maintain the integrity of the Transmission System and enable it to be operated reliably at design voltages and frequency.

[460] The capacity based ancillary services provided from generation capacity must be committed to the provision of the service and cannot be used at the same time

for other purposes. The costs of supplying these services are calculated from the embedded costs of existing generating units and the revenue requirement is determined by multiplying the per-unit embedded cost of capacity for each service by the amount of capacity required to deliver the service.

[461] NS Power is the Transmission Provider and operates in accordance with North American Electric Reliability Corporation (NERC) Reliability Standards and Northeast Power Coordinating Council (NPCC) criteria as approved by the Board. Its responsibility includes determining the need and procurement of sufficient ancillary resources to reliably operate the electrical network. It is also required to make all ancillary services available to all transmission customers. Those customers can purchase capacity based ancillary services from the Transmission Provider, or from a third party, or they can self-supply.

[462] In this application, NS Power requested Board approval of the following revenue requirements and rates for capacity based ancillary services:

Figure 2-8 Revenue Requirement of Capacity Based Ancillary Services

Revenue Requirement of Capacity Based Ancillary Services									
Services	Revenue Requirement ($/kW-yr)			Services Required (MW)			Revenue Requirement ($1000/yr)		
	2022	2023	2024	2022	2023	2024	2022	2023	2024
Regulation	132.0	147.5	153.3	32.0	32.0	32.0	4,224.4	4,720.4	4,904.6
Load Following	170.0	181.2	184.4	176.0	176.0	176.0	29,917.7	31,886.2	32,459.4
Spinning (10-minute)	135.0	140.3	139.5	32.0	32.0	32.0	4,319.3	4,489.8	4,463.6
Supplemental (10-minute)	98.4	125.9	141.8	136.0	136.0	136.0	13,383.9	17,123.9	19,288.4
Supplemental (30-minute)	155.2	152.9	147.3	50.0	50.0	50.0	7,758.2	7,645.6	7,365.4

Figure 2-9 Rates for Capacity Based Ancillary Services

Rates for Capacity Based Ancillary Services			
Services	Rate (\$/MW – month)		
	2022	2023	2024
Regulation	195.8	218.9	226.8
Load Following	1,386.6	1,478.7	1,501.1
Operating Reserve – Spinning	200.2	208.2	206.4
Operating Reserve – Supplemental (10 minute)	620.3	794.1	892.0
Operating Reserve – Supplemental (30 minute)	359.6	354.6	340.6

[Exhibit N-18, SR-01 Attachment 1e, pp. 19-20 of 32]

[463] As noted above, the GRA Settlement Agreement limits the OATT rates to a maximum increase of 1.8% in 2023 and 0% in 2024.

[464] Based on his review of NS Power's evidence, the MEUs' consultant determined that NS Power's approach significantly overstated the costs required for CBAS. In his evidence, Mr. Marshall described the issues contributing to that overstatement and provided his estimation of 2022 rates for the five CBAS items:

> The increases in OATT rates proposed by NS Power are substantive with increases from current rates ranging from 5% to 168% by 2024. WKM proposed CBAS rates for 2022 are close to current rates for Load Following and Spinning Reserve, an increase for 10-Minute Supplemental Reserve and reductions for AGC and 30-Minute Supplemental Reserve.

NS Power and WKM Proposed Rates Compared to Current OATT Rates (\$/MW-month)								
		Transmission		CBAS				
		Point to Point	Network Service	AGC	Load Following	Spinning Reserve	10-Min Reserve	30-Min Reserve
Current	1	4,990	4,241	217	777	166	332	281
NSP proposed								
2022	2	4,682	4,257	196	1,386	200	620	359
2023	3	5,766	5,257	219	1,479	208	794	354
2024	4	6,986	6,340	227	1501	206	891	340
Increase	5=(4-1)/1	**40%**	**49%**	**5%**	**93%**	**24%**	**168%**	**21%**
WKM Proposed								
2022	6			147	732	167	389	143
Increase	7=(6-1)/1			**-32%**	**-6%**	**1%**	**17%**	**-49%**

[Exhibit N-54, p. 24]

[465] In his Opening Statement, Mr. Marshall explained his concerns with the assumptions NS Power used to determine its proposed CBAS rates. His recommendations were repeated in the MEUs Closing Submission:

> 1. **ELIADC Load** – "The ELIADC load is a valuable resource for NS Power. Its contributions to Spinning Reserve, 10 and 30-minute Supplemental Reserves, and Load Following should be included in the costing of those services as recommended in my Evidence." (para. 8 of Ex. N-117)
>
> 2. **AGC Revenue Requirement** – "The current NS Power proposal for Schedule 3(a) (Regulation) is based on an AGC requirement of +/- 16 MW for a total of 32 MW total done through a statistical analysis of NS Power net loads. Including the -16 MW component in the calculation is discriminatory and over charges wholesale market participants for AGC. The Revenue Requirement for Schedule 3(a) should be calculated using only the +16 MW component." (para. 17 of Ex. N-117)
>
> 3. **Load Following Requirement** – "In its Rebuttal, NS Power has redone the analysis for 2021 data and determined a new requirement of 165 MW, which continues to rely on a three standard deviation method. I continue to consider this excessive in the circumstances. I recommend the two standard deviation value of 114.6 MW be used for ratemaking purposes, as it reflects what NS Power states it will require for operational purposes and remains significantly higher than the comparable requirement for NB Power." (para. 21 of Ex. N-117)
>
> 4. **Over Crediting of Wreck Cove in 10-minute spinning reserve costs** – "The correction of Wreck Cove over-credit provided in Paragraph 46 of my Evidence results in a reduction to 10-minute spinning reserve costs and should be required by the Board. Charging the costs associated with Wreck Coves full load toward 10-Minute spinning reserve is not appropriate." (para. 24 of Ex. N-117)
>
> 5. **Inclusion of CTs in costing of 30-minute supplemental reserve** – "I agree that slower ramping on-line generation can provide 30-minute reserve if it is available. However, in winter with high loads and low wind conditions the only resources that may be available are the CTs. The CTs should be included in the costing of 30-minute supplemental reserve as noted in Section X of my evidence." (para. 26 of Ex. N-117)
>
> [MEUs Closing Submission, pp. 10-11]

[466] The MEUs' Closing Submission stated that the Board should accept these recommendations and they should be used the next time NS Power applies for approval of CBAS rates. The MEUs also recommended that NS Power collaborate with Mr. Marshall to obtain information from NPCC about the terms under which New Brunswick's 100 MW of interruptible load is counted toward reserves. That collaboration should address the way interruptible load in Nova Scotia, including the ELIADC load, could be

counted toward reserves, so that such information is available as part of NS Power's next application for approval of CBAS rates.

[467] The MEUs concluded their Closing Submission by stating their concern about NS Power's dominant position in the market:

> The MEUs are and remain particularly concerned that NS Power not be permitted to use its dominant position as the incumbent utility to recover excess costs from wholesale market customers in the competitive market in Nova Scotia.
>
> [MEUs Closing Submission, p. 21]

[468] NS Power did not accept any of those recommendations and expanded on its reasoning in its Reply Submission.

ELIADC Load

[469] Regarding its treatment of the Extra Large Industrial Active Demand Control (ELIADC) load, NS Power provided the following explanation:

> The ELIADC load is optimized along with other supply resources in the development of the day-ahead dispatch plan, providing the least cost dispatch of energy and ancillary services for customers. Scheduling of ELIADC load for the sole purpose of ancillary services would not provide the intended benefits of the rate.
>
> In the development of the day-ahead plan, during hours when the margin between generation plus reserve and load is small, PHP load will be economically dispatched down and therefore be unavailable for Operating Reserve.
>
> … on days when Port Hawkesbury Paper load is not already dispatched down, if the load is available, Nova Scotia Power will use ELIADC in real-time to dispatch PHP load as operating reserves after all other generation reserves are utilized. Currently, this is not the typical operating circumstance, and as such, should not be reflected in the CBAS pricing.
>
> [NS Power Reply Submission, p. 32]

Automatic Generation Control (AGC) Revenue Requirement

[470] On the AGC issue, NS Power stated:

> NS Power commits generation capacity to serve both the +16 MW (RegUp) and the -16 MW (RegDown) components of Regulation service. This capacity is committed in addition to that required to serve load, so the costing for the total of 32 MW of Regulation service is

> included in the calculation for the Regulation service rate. With the high level of wind generation as a percentage of total generation, NS Power requires this level of Regulation service to properly balance the system.
>
> [NS Power Reply Submission, pp. 34]

Load Following Requirement

[471] In addressing Mr. Marshall's recommendation that a 2-standard deviation should be used to determine the CBAS rate associated with the load following issue, NS Power stated:

> Mr. Drover's opening statement includes the following:
>
>> Regarding the load following requirements and the use of a 2 standard deviation analysis versus the 3 standard deviations, Nova Scotia Power believes the analysis that it has completed is more appropriate as it is more comprehensive in the distribution samples that it covers, and it is based on Nova Scotia Power historical load patterns. The three standard deviation approach covers 99.7 percent of normal distribution, which is virtually all samples, whereas the two standard deviation approach only covers 95 percent of the distribution samples. With the variability of the large amount of wind on the system during any given day, and how quickly that can change, the more robust analysis of load following requirements provided by three standard deviations is necessary.
>
> Judgement is required in matters such as this and the views of parties may reasonably differ. For a utility transitioning to higher levels of variable renewable generation as NS Power continues to do, with a penetration of wind which has been confirmed by Mr. Marshall to be greater than that of NB Power, the Board should accept the established practice in Nova Scotia and reject Mr. Marshall's recommendation.
>
> [NS Power Reply Submission, p. 35]

[472] During the hearing, the Board also questioned NS Power regarding its rationale in using the 3-standard deviation versus the 2-standard deviation methodology:

> **Q.** So in terms of the difference between the two methodologies, to me it sounds, at the high end, if that's in fact what you're concerned about, it's really only 2.5 percent difference.
>
> **A.** (Drover) Looking at it that way, that is -- that's right.
>
> **Q.** So really, I guess -- and I understand where you're coming from with the variability and whatnot, but I guess for two and a half percent, is Nova Scotia Power being overly conservative using that three standard deviation methodology?

A. (Drover) Again, I don't think so. Because of the way that we have approached in the past using our historical methods and looking at our systems, I do think that that 2.5 percent is important. And to be honest, there is so much variability, to go to the two standard deviations, I would worry that we would not cover all the variability.

Q. Okay. Do you agree with Mr. Marshall's numbers, though, if, in fact, the two standard deviation methodology was used that the load filing [following] requirement would be roughly 115 megawatts?

A. (Drover) We didn't do that analysis. We only did the three standard deviation analysis. I agree that's what he presented, but I haven't done that myself.

[Transcript, September 21, 2022, pp. 2046-2047]

Over Crediting of Wreck Cove in 10-minute spinning reserve costs

[473] In his response to Mr. Marshall's Opening Statement, Mr. Drover disagreed with Mr. Marshall's suggestion that Wreck Cove was being over-credited for spinning reserves. This was repeated in NS Power's Reply Submission:

Mr. Drover's opening statement provides:

> Regarding Mr. Marshall's claims that Wreck Cove is being over-credited for spinning reserves and the combustion turbines not being considered for 30- minute reserve, Nova Scotia Power disagrees with both statements. As stated in the Nova Scotia Power rebuttal evidence, both Wreck Cove units have the ability to ramp up to full load fast enough to be considered for both spinning reserve and 10-minute reserves, which is how the units are utilized, and therefore are not overstated, but used for both operating reserve calculations.

The Company's development of CBAS charges reflects the actual use of the associated assets on the NS Power system. No adjustments to account for Mr. Marshall's conflicting views are required.

[NS Power Reply Submission, p. 36]

[474] On this topic, NS Power's Rebuttal Evidence stated that Wreck Cove will not be artificially capped in providing spinning reserve capacity. During the hearing, the Board requested clarification of that statement:

Q. So there's a bit of discussion about this, but there's a comment there that Nova Scotia Power makes about Wreck Cove, and it says that "it will not be artificially capped in providing spinning reserve."

I'm wondering if you could explain what is meant by "artificially capped".

A. (Drover) So spinning reserve is a function of 10-minute reserve. Our 10-minute reserve requirement in totality is 168 megawatts, which is the size of our larger single contingency, which is Point Aconi.

Spinning reserve is a component of that, which is 32 megawatts. What we were trying to illustrate there is that Wreck Cove, with its fast-acting generation and its ability to ramp up quickly, should be counted as both, but not double counted. So 32 megawatts of Wreck Cove's ability would be for spinning reserve, and then the remaining reserves that it has available would [be] in the 10-minute reserve.

Q. And how did you see Mr. Marshall's proposal or suggestion on this point as artificially capping Wreck Cove?

A. (Drover) The way we viewed it was that there was less than 32 megawatts of spinning reserve that was included in his calculation, where we were saying that the full 32 could be used for spinning.

[Transcript, September 21, 2022, pp. 2116-2117]

Inclusion of Combustion Turbines (CTs) in costing of 30-minute supplemental reserve

[475] Regarding 30-minute supplemental reserve costs, Mr. Marshall's evidence suggested that NS Power omitted using less expensive CTs for that reserve requirement:

93. The $/kW-yr cost for the 30-Minute Supplemental Reserve for 2022 is determined in Table E4-7 of Attachment 1 in NSPI (MUNIS) IR-41 as $152.91/kW-yr. It is multiplied by the 50 MW obligation to determine a Revenue Requirement for 10-Minute Supplemental Reserve equal to $7,645,500 for 2022.

94. WKM agrees that 50 MW is the correct obligation of NS Power for 30-Minute Supplemental Reserve but disagrees with the $152.91/kW-yr cost as NS Power does not include available CT capacity in Table E4-7 calculation of cost. It only includes thermal coal units and the oil and gas units at Tufts Cove.

[Exhibit N-54, p. 21]

[476] In addressing this concern, NS Power stated that the CTs do contribute to 30-minute supplemental reserve after their contribution to 10-minute reserve requirements, but their 30-minute contribution is negligible:

…All of the Combustion Turbines are also fast acting generation units and primarily contribute to 10-minute non-spinning reserve before 30-minute reserve. The number of hours that the CTs are operating for capacity and therefore contribute to overall system 30-minute reserve is negligible. This approach ensures that the Wreck Cove units and the CTs are properly accounted for in Spinning Reserves, 10-minute reserves and 30-minute reserves without being double counted.

[Exhibit N-142, pp. 4-5]

[477] In its Reply Submission, NS Power stated:

> While under some circumstances CTs can contribute to 30-minute operating reserves, it is more appropriate to assess the use of generation resources considering their intended use within the overall portfolio for the provision of energy and ancillary services. In this context, CTs are fast acting generation resources which are used to support 10-minute reserve requirements. Likewise, coal, gas, and heavy fuel oil fired generation resources tend to be slow to respond and are used to support 30-minute reserve requirements.
>
> The capacity available from fast-acting CTs may at times exceed the 10-minute operating reserve requirements; however, like all generators in the fleet, CTs are subject to planned maintenance outages, forced outages, de-ratings, reassignment for other purposes such as voltage support, and transmission constraints which may limit their output. Based on a portfolio view of the generation fleet, the assignment of CT costs to the provision of capacity based ancillary services for providing 10-minute operating reserves is appropriate.
>
> [NS Power Reply Submission, pp. 37-38]

7.13.6.1 Findings

[478] As stated earlier, the MEUs' Closing Submission noted their support for Board approval of the GRA Settlement Agreement, but also sought Board approval of the CBAS recommendations proposed by Mr. Marshall. In addition, they stated that the Board should accept these recommendations and they should be used the next time NS Power requests approval of CBAS rates. The MEUs also recommended that NS Power obtain information from NPCC about the terms under which interruptible load is counted toward reserves. In its response in Undertaking U-14, NS Power stated that interruptible load is counted toward 10-minute reserve when the required amount is not available from generation resources. It also stated that planning to interrupt interruptible loads is not a consideration in meeting day-ahead load and reserve requirements. The Board considers there may be some value in alternate treatment of interruptible loads and directs NS Power to explore options with NPCC. In the next GRA, NS Power is directed to file its analysis of cost implications associated with alternative treatment of interruptible loads.

[479] In these findings, the Board addresses each of the five recommendations included in the MEUs' Closing Submission.

[480] The Board understands the unique nature of the ELIADC tariff developed with the intention of benefitting PHP, as well as the broader NS Power customer base. Although the PHP load could be used to address spinning or supplemental reserve requirements, the Board accepts NS Power's position that scheduling ELIADC load for the sole purpose of ancillary services would not provide the intended benefits of the rate. Recognizing that the tariff is limited in its term and is due for review prior to the end of 2023, parties may choose to make further submissions on this issue when that tariff is being reviewed, or during the COSS, or during the next GRA.

[481] On the AGC issue and NS Power's treatment of the -16 MW requirement in its CBAS calculation, the Board views Mr. Marshall's concern worthy of further consideration. The Board notes Mr. Marshall's reference in Exhibit N-117 to FERC Order 890, paragraph 690, which was quoted as:

> *"If the transmission provider elects to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances, the transmission provider should file a rate schedule* ***and demonstrate that these charges do not allow for double recovery of such costs****."*

[482] Prior to the next GRA, NS Power is directed to explore alternative treatment of the -16 MW requirement and to demonstrate that it is not double charging transmission customers.

[483] The load following costing issue focuses on whether the 2-standard deviation or the 3-standard deviation methodology should be applied in determining the associated CBAS rate. In considering this question, the Board notes the following

statements contained in NS Power Control Centre Operations documentation, provided as Attachment 2 in NS Power's response to Munis IR-39:

> For ratemaking purposes, 3-sigma analysis is typically used, providing for 99.7% of samples.
>
> …
>
> Operationally, net load variations would be managed through the day-ahead schedule, but it would reasonable expected [sic] that 2-sigma or 95% probability of variation would be required.
>
> [Exhibit N-39, Attachment 2, p. 5]

[484] The Board is not persuaded that NS Power has sufficiently justified the higher cost or the need to apply a 99.7% probability in the load following CBAS rate calculation. NS Power is directed to apply the 2-standard deviation methodology in this CBAS calculation when submitting its compliance filing.

[485] Regarding the suggestion that Wreck Cove capacity may be over-credited in the 10-minute spinning reserve costs calculation, the Board understands NS Power's evidence to be that the units are utilized for spinning reserve and for 10-minute supplementary reserve, so the CBAS charges reflect that actual use of those assets. However, considering Mr. Marshall's questioning of the calculation, NS Power is directed to clearly demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization is represented in its calculations.

[486] Regarding inclusion of less expensive CTs in the CBAS costing calculations for 30-minute supplemental reserve, the Board understands NS Power's evidence to be that the CT contribution to that reserve capacity is negligible, so it is not factored into the calculation. Considering that there are currently seven units in service, the Board finds NS Power's explanation to be lacking and directs that a more fulsome explanation be provided, no later than in its next GRA, to justify its position in this matter.

7.13.7 Other Tariffs and Regulations

[487] In its application, NS Power also applied for changes to Regulation 7 of its Board-approved Regulations, which sets out miscellaneous charges for various services provided by the Utility to its customers. These included: 7.1 Schedule of Charges; 7.2 Schedule of Wiring Charges; and 7.3 Schedule of Load Research Monitoring, Reporting and Analytical Charges. NS Power reviewed these charges in light of changes in service delivery, cost structure, and technological advances. For many of the charges, the implementation of remotely-read AMI meters has caused the charges to decrease, reflecting the savings achieved by performing connections, disconnections and meter readings from a central office, instead of dispatching technicians to customer sites. Revisions to Regulation 7.1 include: the separation of connection and disconnection charges into different rates for customers with remotely-read meters and non-remotely read meters; the addition of non-standard meter reading charges; and the removal of the rates associated with the discontinued Mobile Radio Network access service.

[488] The Board notes there were also proposed revisions to the Distribution Tariff as well as other tariff revisions required to implement the Storm Rider and DSM Rider.

[489] In the GRA Settlement Agreement, the parties agreed with all other proposed revisions to NS Power's tariffs and miscellaneous charges in the Regulations, except as noted in the settlement (i.e., Pole Attachment Fee, OATT, and CBAS, which are also discussed elsewhere in this decision). Further, the Board notes that, elsewhere in this decision, it has made findings about the AMI opt-out fee, CBAS and the MEUs' requested BUTU GHG credit.

7.13.7.1 Findings

[490] Subject to the Board's findings elsewhere in this decision, and NS Power providing its compliance filing, the Board approves the proposed changes to the miscellaneous charges in Regulation 7 and the proposed revisions to the various tariffs, including the Distribution Tariff.

7.13.8 BUTU GHG Credit

[491] The MEUs asked the Board to establish a credit in the embedded cost calculation for NS Power's Backup and Top-up (BUTU) Tariff for the reduction in GHG compliance costs to NS Power due to the movement of portions of their load to third party suppliers. The MEUs noted that the shifting of this load from NS Power's system reduced the RES-eligible energy NS Power must acquire and freed up emissions cap room that would be used for the benefit of other customer classes to reduce GHG and sulfur dioxide compliance costs.

[492] The MEUs submit that since these benefits are the direct result of their removal of their load from the NS Power system, they should be provided "solely to the customer class whose actions have created this benefit" and not socialized to the benefit of all customers. The MEUs said this would be like the interruptible credit available to large industrial customers who have agreed that service to them may be interrupted in times of high demand.

[493] In its Rebuttal Evidence, NS Power challenged the analogy to the credit provided through the Large Industrial Interruptible Rider:

> The LIIR credit relates to a distinct difference in service taken by the LIIR customers (non-firm service) versus firm service customers (including BUTU customers) and the associated long-term savings this conveys to other customers. The long-term capacity

> savings are distinct and reasonably quantifiable (the cost of a combustion turbine). The MUNIS have opted out of bundled service entirely. The decision to opt for competitive supply is presumably taken for the financial benefits it provides to the MUNIS. The decision to take BUTU service from NS Power is presumably because this is the low-cost BUTU service option available. Unlike the Large Industrial Interruptible customers, the MUNIS are not taking a lesser form of service and this is not tied to a GHG benefit or any other emission benefit (or cost) that could accrue to bundled service customers.
>
> [Exhibit N-102, p. 147]

[494] In their Closing Submission, the MEUs disagreed with these assertions and said they were also taking a lesser form of service under the BUTU Tariff because they were significantly reducing the energy requirements being placed on NS Power's system. They noted that this reduction was directly tied to a GHG benefit that currently accrued to bundled service customers "as each MWh of reduction in load reduces the marginal cost of GHG compliance that is otherwise borne by the overall system."

[495] The MEUs also emphasized they were not seeking a credit for simply departing NS Power's system or reducing their consumption. Rather, they submitted that the proposed credit was integral to proper pricing under the BUTU Tariff. They also noted that if they do not use the BUTU Tariff, they will not receive any form of credit under their proposed approach. The MEUs accept that if "the customers leave the system or reduce load but do not take service under the BUTU Tariff … no credit would be applicable or otherwise paid to the MEUs."

[496] In its Reply Submission, NS Power further contrasted the proposed credit under the BUTU Tariff with the Large Industrial Interruptible Rider credit. NS Power also noted that taking BUTU service from NS Power is not mandatory in the wholesale market and that if the MEUs are able to acquire backup service of firm supply from another source, they are free to do so.

[497] NRR supported the proposed GHG credit for the BUTU Tariff in its Closing Submission. NRR submitted that the provisions under the *Electricity Act* and the *Renewable Electricity Regulations* establishing a wholesale market for the MEUs were intended to provide them with access to new competitive opportunities and increase the amount of renewable energy on the system. NRR said the credit recognized the value provided by the MEUs' actions in participating in the competitive market and directly reducing provincial GHG emissions on a go-forward basis. The MEUs relied on these comments in their Reply Submission.

[498] The only other parties to address this issue were the Industrial Group and Dalhousie University in their Reply Submission. They noted that the MEUs already reduce their contribution to fixed costs by removing their load from NS Power's system and that these costs are paid by above-the-line customers. They submitted that this "negotiated concession to the MEU's during the development of the OATT whereby they are not responsible for the payment of exit fees should be considered before considering crediting the MEU's from leaving the system."

[499] Having said that, the Industrial Group and Dalhousie University noted that the GRA Settlement Agreement requires a consultative process for a new cost of service study which would provide an opportunity to comprehensively review the cost inputs of the BUTU Tariff at the same time as cost inputs for bundled services to determine if there is any "cross-subsidization" in the absence of the requested credit. They submitted the Board should not approve a stand-alone GHG credit in this proceeding.

7.13.8.1 Findings

[500] The Board agrees that if a credit were to be considered for the MEUs to account for any system benefits relating to GHG compliance costs, any incremental benefits associated with the removal of the MEUs' load from the NS Power system should be offset by incremental costs associated with the removal of that load. Additionally, as NS Power points out in its Reply Submission, the administration of the credit may result in administrative costs that would also have to be considered. However, the Board concludes there should not be any credit, so this does not need to be addressed.

[501] The Board disagrees that the claimed credit is comparable to the Large Industrial Interruptible Rider. First, the Board accepts NS Power's position that interruptible service is a lesser form of service compared to firm service. Second, the Interruptible Rider was designed specifically to avoid having to build additional capacity on the system. In other words, the rate was specifically designed to produce the system benefit for which those on the rider are being compensated.

[502] In contrast, if there is any GHG compliance system benefit arising from the BUTU Tariff, it is ancillary to the main purpose of the tariff. The BUTU Tariff was not designed with the main objective of producing that result. It was designed to benefit the MEUs.

[503] The BUTU Tariff was not part of the original development of the OATT that was approved by the Board in 2005. It is not a required tariff under the *Electricity Act* and was developed later to support or enable the MEUs to access a competitive supply of electricity at their request, as was noted by the Board in its decision approving the BUTU Tariff in 2009:

[3] NSPI, in its prefiled evidence, provided both a summary of events leading up to this application and the application:

> On February 1, 2007 the *Electricity Act* came into effect, opening the Nova Scotia electricity market for wholesale competition. NSPI's Municipal class customers are eligible, at their option, to take some or all of their electric energy requirements from a supplier other than NSPI. To date, none of these customers have selected this option, and they have requested that additional tariffs applicable to the wholesale market, namely "backup, top-up and spill rates" be developed and offered by NSPI.
>
> In March 2007, after discussions with Municipal class customers and renewable energy stakeholders, the Government of Nova Scotia requested that these rates be developed and brought forward for NSUARB approval. Since that time, NSPI has worked with stakeholders to reach common understanding of the needs of these customers, the potential effects on other customers, and to subsequently prepare an application for Board approval of new tariffs.
>
> On September 12, 2007, NSPI, wholesale Municipal class customer representatives, Suez Renewable Energy North America (SRENA, a wind energy producer being considered by the Municipal utilities), Scotia Investments (the landowner of the proposed wind farm), NSUARB staff and N.S. Department of Energy (NSDoE) staff began a series of meetings to discuss the issues. Subsequent meetings of this group, or subsets as agreed to by the larger group, were held on September 28, October 10, October 18, November 16, December 5, 2007, and February 21, April 10 and April 24, 2008.
>
> These collaborative meetings helped to clarify the issues and increase the understanding of all involved. The Company and stakeholders were able to reach agreement in a number of areas and have agreed to present their individual perspectives to the UARB on any remaining issues.
>
> This application presents NSPI's proposed rates for backup, top-up and spill services. Consistent with regulation in Nova Scotia, the proposed rates are based on sound costing principles and are fair to all customers. The proposed backup and top-up tariffs are limited to Municipal class customers who are participating in the electricity market for wholesale competition under the *Electricity Act* S.N.S., 2004 c.25. NSPI requests that the Board approve the tariff designs utilized in this application only for use by this limited group of customers. Because the cost of supplying various amounts of incremental demand may differ from marginal cost (which relates to very small demand variance), applying a marginal-cost based pricing approach to larger amounts of load can come with serious financial risk.

> The spill tariff is available to third party non-dispatchable generators serving participating Municipal customers' load.
>
> [*Re Nova Scotia Power Incorporated*, 2009 NSUARB 1, para. 3]

[504] The Board also noted in that decision that service under the BUTU Tariff was voluntary, and it was contemplated at the time that other providers might also supply these services in the future:

> [17] NSPI initiated the process leading to these rates at the request of the Province of Nova Scotia and the municipal utilities. The municipal utilities wish to purchase some or all of their power and energy requirements from a non-regulated supplier, other than NSPI, as is contemplated by the *Electricity Act*. During the early transition, at least, they require a back-stopping arrangement be in place which facilitates their ability to transfer to another supplier, yet at the same time ensure their customers reliable service. As the wholesale market matures there may well be a sufficient number and diversity of independent suppliers, that this service by NSPI may no longer be needed. As was pointed out repeatedly in the hearing, it is open to the municipal utilities to take this service or not, as their needs require. If, as the market evolves, companies such as CBEX can supply these services at a price more favourable than NSPI, while meeting the municipal utilities' reliability needs, then the municipal utilities are obviously free to contract with companies other than NSPI.
>
> [*Re Nova Scotia Power Incorporated*, 2009 NSUARB 1, para. 17]

[505] Additionally, if the MEUs removed their load from the system and took no service of any nature from NS Power, the same potential for GHG compliance benefits to the system would exist. In such a case, the MEUs concede that no credit would be applicable or paid to them. In the Board’s view, the MEUs should not be entitled to a credit simply because they have elected to take service under the BUTU Tariff to meet their own specific needs and requirements when they would not receive one otherwise. Furthermore, the BUTU Tariff is available once the MEUs have removed their load (or part of it) from the NS Power system. If there are any GHG compliance benefits, they arise from the election to remove load from the system and take it from another supplier.

[506] The BUTU Tariff does not remove any load from the NS Power system. It provides a backup and top-up service for load that has been removed. It is an optional service, and it may also be supplied by another provider. Although the Board is not aware

that there are any other suppliers for this service in the market, it was contemplated that as the market evolved this could occur. If NS Power's embedded cost of service were to be reduced by a credit for GHG compliance benefits, this could make the materialization of competitive sources for this service in the market even more unlikely as the cost to compete would be that much lower.

[507] Ultimately, the Board disagrees that the change to an embedded cost of service methodology for the BUTU Tariff leads inevitably to the need to provide a credit for any incidental incremental benefits to the NS Power system. To the extent that there are any, these benefits will flow through NS Power's cost of service and reduce the embedded costs in all customer rates, including the BUTU Tariff. In the circumstances the Board finds this is appropriate.

8.0 SUMMARY OF MAJOR FINDINGS AND DIRECTIVES

[508] The Board has approved most of the components of the GRA Settlement Agreement including:

- An average rate increase across all customer classes of 6.9% (including fuel and non-fuel costs) in each of 2023 and 2024;
- Maintaining NS Power's current return on equity of 9.0%, with an earnings band of 8.75% to 9.25%. The equity thickness for rate setting purposes increases from 37.5% to 40.0%;
- Agreeing in principle to the establishment of a Decarbonization Deferral Account to address the retirement of coal plants and related decommissioning costs, subject to a further consultative process;
- Implementing a Storm Cost Recovery Rider for a three-year trial period, and a DSM Cost Recovery Rider;

- Conducting an updated Cost of Service Study and Line Loss Study before the next GRA or by December 31, 2025, whichever is sooner, subject to stakeholder engagement;

- Applying a 25% reduction to the proposed increase to the 2023 customer charges;

- Increasing the credit amount in the Large Industrial Interruptible Rider; and

- Capping the Open Access Transmission Tariff at a maximum increase of 1.8% in 2023 and 0% in 2024.

[509] The Board has not approved three items in the GRA Settlement Agreement:

- The proposed AMI opt-out fee;

- The regulatory amortization of the Annapolis Tidal Generation Facility, which is to remain in rate base; and

- The inclusion of the four Maritime Link transmission capital projects in rate base, at this time.

[510] The Board has also approved a Settlement Agreement between NS Power and the telecommunications carriers, which included a negotiated settlement of the Pole Attachment Fee.

[511] The Board has denied the Municipal Electric Utilities' request for a Wholesale Market Backup/Top-up (BUTU) Tariff GHG credit. However, the Board has accepted one of their recommendations for Capacity Based Ancillary Services, and directed a review of their other recommendations.

[512] NS Power is directed to:

- Submit annual reports on April 1, 2024-2026, summarizing actual storm restoration costs for each year of the Storm Rider trial period; [para. 332]

- Include full detail on all storm restoration, storm hardening and vegetation management costs in each Storm Rider cost recovery application submitted during the three-year trial period. Also, NS Power is to engage with stakeholders to determine the specifics for how this information is to be presented, in advance of the first Storm Rider cost recovery application; [para. 338]

- Engage in a consultative process to develop a Climate Change Adaptation Plan to be filed with the Board no later than the end of 2025; [para. 340]

- File an update about a DSM true-up for prior period variances no later than the first application to adjust the DSM Rider approved in this decision; [para. 359]

- File semi-annual progress reports about the stakeholder engagement process for the Cost of Service and Line Loss Studies, starting January 31, 2024; [para. 367]

- File a depreciation study before its next GRA and include the scope of the depreciation study as part of its DDA consultative process with stakeholders and the resulting report on that process; [para. 374]

- Exclude all Part VI.1 tax transactions and amounts from its regulated statements in the future, and to adjust for any amounts currently included in the regulated financial statements; [para. 379]

- Keep the Annapolis Tidal Generation Facility in property, plant and equipment; [para. 387]

- Engage in a review process, with the Affordable Energy Coalition and the Consumer Advocate, to evaluate the impact of the changes approved in 2013 to bill payment, credit and collection matters, to examine if further changes are needed, and to establish a systematic evaluation methodology that can be applied to future changes. NS Power is to file a report by April 30, 2023; [para. 411]

- To explore options with NPCC about alternative treatment of interruptible loads and to file its analysis of cost implications in the next GRA; [para. 478]

- Explore, prior to the next GRA, alternative treatment of the -16 MW requirement in AGC and to demonstrate that it is not double charging transmission customers; [para. 482]

- Demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization for Wreck Cove is represented in its CBAS calculations; and [para. 485]

- Provide a more fulsome explanation, no later than in its next GRA, to justify its position to exclude CT units from its costing of 30-minute supplemental reserve for the CBAS calculations. [para. 486]

9.0 COMPLIANCE FILING

[513] NS Power is to file a compliance filing based on the Board's findings in this decision. The compliance filing is to include, among other things:

- The proposed changes to the miscellaneous charges in Regulation 7 and the proposed revisions to the various tariffs, including the Distribution Tariff, subject to the Board's findings elsewhere in this decision; [para. 490]

- Forecasted interest calculations to the end of 2024 for the existing deferrals approved for the recovery of interest at NS Power's WACC; [para. 114]

- Required changes to NS Power's FAM Plan of Administration based on the recovery of fuel and purchased power costs under the GRA Settlement Agreement and approved in this decision; [para. 159]

- Updated DCRR charges for 2023, recognizing that this GRA decision is being released after the October 1 DCRR filing date noted in the tariff; [para. 358] and

- Application of the 2-standard deviation methodology in the CBAS calculation. [para. 484]

[514] NS Power is directed to file a compliance filing no later than two weeks after the date of this decision. Intervenors will have two weeks from the date that NS Power files its compliance filing to provide submissions to the Board. NS Power may file a reply within one week from the date the Intervenors file submissions.

[515] The Board has approved the average rate increases of 6.9% across all customer classes in each of 2023 and 2024, subject to the Board's findings in this decision. Schedule B attached to the GRA Settlement Agreement (i.e., Appendix B in this decision) sets out the rate increases per customer class, to be confirmed in the compliance filing. The Board approves the rates and charges for 2023 effective the date of this decision and the rates and charges for 2024 effective January 1, 2024.

[516] An Order will issue following the compliance filing.

DATED at Halifax, Nova Scotia, this 2nd day of February 2023.

Stephen T. McGrath

Roland A. Deveau

Steven M. Murphy

APPENDIX A

Intervenors **(Counsel or representative)**	**Witnesses/Pre-filed Evidence**
Nova Scotia Power Inc. Colin Clarke, K.C. Blake Williams	**Policy/Finance and DDA** Peter Gregg - President & CEO Chris Smith - EVP, Finance Lia Macdonald - VP Transmission/ Distribution/Delivery Craig Flemming - Director, Finance Brian Curry, Director - Regulatory Affairs Eric Ferguson - Senior Director Pricing Michael Willett -Director, Regulatory Finance John Reed CEO, Concentric Energy Advisors **Cost of Capital** Peter Gregg - President & CEO Chris Smith - EVP, Finance Craig Flemming - Director, Finance Michael Willett - Director, Regulatory Finance James Coyne - Senior VP, Concentric Energy Advisors **Riders/Rates/COS** Craig Flemming - Director, Finance Brian Curry - Director, Regulatory Affairs Eric Ferguson - Senior Director Pricing Michael Willett - Director, Regulatory Finance Voytek Grus - Manager, Costing and Rates Matthew Drover - Senior Director, Transmission & Distribution Daniel Dane - EVP, Concentric Energy Advisors Bickey Rimal - Assistant VP, Concentric Energy Advisors **Fuel/Purchased Power/Load** David Landrigan - VP Commercial Marie MacLean - Director, Fuels Brendan Chard - Director, Portfolio Optimization Michael Willett - Director, Regulatory Finance

Board Counsel S. Bruce Outhouse, K.C.	**<u>Bates White</u>** Vincent Musco Karen Morgan Nick Puga **<u>Grant Thornton</u>** Tom Brockway Barry Griffiths Angie Brown **<u>Synapse Energy Economics Inc.</u>** Melissa Whited Karl Pavlovic – PCMG Laurence Booth **<u>Plenus Actuaries and Consultants</u>** Paul Burnell
Consumer Advocate William J. Mahody, K.C. Emily Mason Christine Murray	**<u>Resource Insight Inc.</u>** Paul Chernick John Wilson J. Randall Woolridge
Small Business Advocate E.A. Nelson Blackburn, K.C. Melissa P. MacAdam	**<u>Daymark Energy Advisors</u>** John Athas Melissa Whitten
Industrial Group Nancy G. Rubin, K.C. Brianne E. Rudderham Dylan MacDonald	**<u>Drazen Consulting Group, Inc.</u>** Mark Drazen
Affordable Energy Coalition Peter Duke Brian Gifford	
Dalhousie University Nancy G. Rubin, K.C. Brianne E. Rudderham Dylan MacDonald	
Ecology Action Centre Jacob Thompson	

Eastlink Robert G. Grant, K.C.	**AGBriggs Consulting Inc.** Andrew Briggs Steve Irvine – Senior VP Energineer and Chief Technology Officer
Efficiency One James G. Gogan David Irvine	**Elenchus** John Todd
Freeman Lumber Noah Entwisle	
Heritage Gas Limited Michael Johnston Kristen Wilcott	
Mainland Telecom Inc. Burt McCaffrey	
Municipal Electric Utilities of Nova Scotia James MacDuff Melanie Gillis	Don Regan – Superintendent, Berwick Electric Commission Albert Dominie **WKM Energy Consultants Inc.** William Marshall
NCS Managed Services Emerich R. Winkler Jr.	
Nova Scotia Department of Natural Resources and Renewables Daniel Boyle Jeremy Smith David Miller Michelle Miller Peter Craig Christina Wells	**Power Advisory LLC** Christine Runge John Dalton
Nova Scotia Liberal Caucus Zach Churchill, M.L.A., Leader Kirby McVicar Callie Franson	Zach Churchill, M.L.A., Leader

Nova Scotia NDP Caucus Claudia Chender, M.L.A., Leader Susan Leblanc, M.L.A. Allison Smith Joanne Hussey	Claudia Chender, M.L.A., Leader
Port Hawkesbury Paper LP James MacDuff Melanie Gillis	
Rogers Communications Canada Inc. Leslie Milton	Dean Abbass – General Manager, Cable Operations as Seaside Communications
Xplore Inc. Carl MacQuarrie	Carl MacQuarrie – Regulatory Counsel at Xplore

APPENDIX B

Anticipated Revenue Increase Table

	2023				2024			
	Base Cost Rates	FAM AA/BA Riders	DSM Rider	Total	Base Cost Rates	FAM AA/BA Riders	DSM Rider	Total
Domestic Service Tariff								
Fuel	0.7%	0.0%	0.0%	0.7%	6.4%	0.0%	0.0%	6.4%
Non-Fuel	2.7%	0.0%	3.5%	6.2%	0.0%	0.0%	0.4%	0.4%
Total	**3.3%**	**0.0%**	**3.5%**	**6.9%**	**6.4%**	**0.0%**	**0.4%**	**6.8%**
Small General Tariff								
Fuel	0.7%	0.0%	0.0%	0.7%	8.3%	0.0%	0.0%	8.3%
Non-Fuel	2.9%	0.0%	4.8%	7.7%	0.0%	0.0%	0.1%	0.1%
Total	**3.6%**	**0.0%**	**4.8%**	**8.4%**	**8.3%**	**0.0%**	**0.1%**	**8.5%**
General Tariff								
Fuel	2.8%	0.0%	0.0%	2.8%	6.8%	0.0%	0.0%	6.8%
Non-Fuel	0.3%	0.0%	4.0%	4.3%	0.0%	0.0%	0.2%	0.2%
Total	**3.1%**	**0.0%**	**4.0%**	**7.1%**	**6.8%**	**0.0%**	**0.2%**	**7.0%**
Large General Tariff								
Fuel	1.7%	0.0%	0.0%	1.7%	8.3%	0.0%	0.0%	8.3%
Non-Fuel	1.8%	0.0%	4.8%	6.6%	0.0%	0.0%	0.0%	0.0%
Total	**3.5%**	**0.0%**	**4.8%**	**8.3%**	**8.3%**	**0.0%**	**0.0%**	**8.3%**
Small Industrial Tariff								
Fuel	-0.7%	0.0%	0.0%	-0.7%	8.4%	0.0%	0.0%	8.4%
Non-Fuel	4.2%	0.0%	4.7%	8.8%	0.0%	0.0%	0.0%	0.0%
Total	**3.5%**	**0.0%**	**4.7%**	**8.1%**	**8.4%**	**0.0%**	**0.0%**	**8.5%**
Medium Industrial Tariff								
Fuel	0.7%	0.0%	0.0%	0.7%	8.0%	0.0%	0.0%	8.0%
Non-Fuel	5.0%	0.0%	2.2%	7.2%	0.0%	0.0%	0.2%	0.2%
Total	**5.7%**	**0.0%**	**2.2%**	**7.9%**	**8.0%**	**0.0%**	**0.2%**	**8.2%**
Large Industrial Tariff								
Fuel	5.2%	0.0%	0.0%	5.2%	4.8%	0.0%	0.0%	4.8%
Non-Fuel	-3.3%	0.0%	3.0%	-0.3%	0.0%	0.0%	0.0%	0.0%
Total	**1.9%**	**0.0%**	**3.0%**	**4.9%**	**4.8%**	**0.0%**	**0.0%**	**4.8%**

Municipal Tariff								
Fuel	-3.4%	0.0%	0.0%	-3.4%	5.9%	0.0%	0.0%	5.9%
Non-Fuel	3.9%	0.0%	4.8%	8.8%	0.0%	0.0%	0.2%	0.2%
Total	**0.5%**	**0.0%**	**4.8%**	**5.4%**	**5.9%**	**0.0%**	**0.2%**	**6.1%**
Unmetered								
Fuel	3.0%	0.0%	0.0%	3.0%	0.1%	0.0%	0.0%	0.1%
Non-Fuel	-3.5%	0.0%	0.7%	-2.8%	0.0%	0.0%	0.0%	0.0%
Total	**-0.5%**	**0.0%**	**0.7%**	**0.2%**	**0.1%**	**0.0%**	**0.0%**	**0.2%**
Total FAM Classes								
Fuel	1.5%	0.0%	0.0%	1.5%	6.6%	0.0%	0.0%	6.6%
Non-Fuel	1.8%	0.0%	3.6%	5.4%	0.0%	0.0%	0.3%	0.3%
Total	**3.3%**	**0.0%**	**3.6%**	**6.9%**	**6.6%**	**0.0%**	**0.3%**	**6.9%**

NOTE: The increases identified above are subject to change as a result of the proceeding's compliance filing.

PRINCE EDWARD ISLAND
Regulatory & Appeals Commission
Commission de réglementation et d'appels
ÎLE-DU-PRINCE-ÉDOUARD

Docket: **UE20946**
Order: **UE23-04**

IN THE MATTER of an application by Maritime Electric Company, Limited for an order approving rates, tolls and charges for electric service for the years March 1, 2023 to February 28, 2026, pursuant to section 20 of the *Electric Power Act*, RSPEI 1988, c. E-4.

CERTIFIED TRUE COPY

Nicole McKenna,
Commission Legal Counsel
Prince Edward Island Regulatory and Appeals Commission

Order

BEFORE THE COMMISSION ON Monday, the 24th day of April, 2023.

J. Scott MacKenzie, K.C., Chair
M. Douglas Clow, Vice-Chair
Erin T. Mitchell, Commissioner

OVERVIEW OF THE APPLICATION:

1. On June 20, 2022, Maritime Electric Company, Limited ("MECL") filed an application with the Prince Edward Island Regulatory and Appeals Commission (the "Commission") seeking approval for new electric rates, tolls and charges for a three year period (the "GRA" or the "Application"). If approved, new rates for all rate classes would come into effect on March 1st in each of 2023, 2024 and 2025.

2. In the GRA as filed, MECL sought to increase the energy charge per kWh for each rate class. If approved, the energy charge would increase by 3.1 percent to 4.0 percent. For the benchmark Residential and General Service customer, the total cost of electricity would increase between 2.9 percent to 3.1 percent per year. The actual increase for a particular customer would vary depending on their rate class and energy consumption.

3. The rates proposed in the GRA assumed that MECL's return on average common equity ("ROE") would increase from 9.35 percent to 9.95 percent based on 40 percent average common equity.

4. Following receipt of the GRA, the Commission gave public notice of the Application through a publication in local newspapers and on the Commission website. Interested members of the public were given the opportunity to issue questions to MECL, submit comments to the Commission, and apply for intervener status.

5. The Prince Edward Island Energy Corporation ("PEIEC") applied for and was granted Added Party Intervener status.[1] There were no other requests for intervener status.

6. In early January 2023, MECL and PEIEC sought Commission approval to enter into settlement negotiations with respect to all matters contained in the GRA.[2] The request was made in accordance with the Commission's *Rules of Procedure for Negotiated Settlements In Matters of Utility Regulation* ("*Rules of Negotiated Settlement*").

7. On January 12, 2023, the Commission approved the request and permitted MECL and PEIEC to enter into settlement negotiations, subject to certain conditions. These conditions were set out in the Commission's letter of direction dated January 12, 2023.[3]

8. On February 10, 2023, a report was received from the Commission's independent expert, London Economics International LLC ("London Economics").[4] London Economics was retained by Commission staff to provide an expert opinion regarding a just and reasonable ROE for MECL. London Economics independently estimated the ROE for the rate setting period and recommended an ROE of 9.7 percent based on the proposed capital structure of 40 percent equity.

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[1] Order UE22-05
[2] Exhibit M-10 and Exhibit EC-3
[3] Exhibit C-3
[4] Exhibit C-5

9. On April 4, 2023, a settlement between MECL and PEIEC was filed with the Commission (the "Proposed Settlement").[5] The Proposed Settlement amends certain parts of the GRA as filed. As a result of the amendments, MECL's revenue requirement over the three year rate setting period has been reduced by approximately $5.8 million.

10. The reduction in revenue requirement is driven primarily by two amendments to the GRA as filed:

    a) **Reduction in the Proposed ROE**: In the Proposed Settlement, the ROE used to calculate MECL's revenue requirement has been reduced from 9.95 percent to 9.35 percent. MECL would have the ability to earn an additional 0.35 percent up to a maximum of 9.7 percent. If approved, this "deadband" of a further 0.35 percent would give MECL the opportunity to earn an ROE of up to 9.7 percent through operational efficiencies and/or business growth.

    b) **Reduction in the Provincial Debt Repayment**: After the GRA was filed in June 2022, PEIEC provided MECL with a revised repayment schedule for the provincial debt repayment costs. The repayment schedule was revised to reflect insurance proceeds associated with delays in the Point Lepreau Nuclear Generating Station refurbishment, including a related interest swap gain. There was no change to the collection period of the debt.

11. These two amendments, taken together, represent approximately 90 percent of the total reduction in the revenue requirement.

12. The reduction in the annual revenue requirement results in a reduction in the proposed increase to customer rates. As a result, the Proposed Settlement would see electric rates increase by 2.6 percent in 2023, 2.6 percent in 2024, and 2.7 percent in 2025, depending on a customer's rate class and energy consumption. The below table shows the annual rate increase proposed in the GRA as filed versus the annual rate increase in the Proposed Settlement:

Annual Rate Increase for a Benchmark Customer			
	2023/2024	**2024/2025**	**2025/2026**
GRA as filed	3.0%	3.0%	3.0%
Settlement	**2.6%**	**2.6%**	**2.7%**

13. The Proposed Settlement, if approved, would see new electric rates come into effect on May 1, 2023, March 1, 2024 and March 1, 2025.

14. After receiving the Proposed Settlement, the Commission determined that a public hearing would be held. The Commission gave public notice of the Proposed Settlement and the

[5] Exhibit M-14

hearing in local newspapers and on the Commission website. Interested members of the public were invited to submit comments to the Commission in advance of the hearing.

15. The hearing was held in the Commission hearing room on April 18, 2023. The hearing was open to the public and was broadcast live on the Commission's website.

16. In the course of the hearing, MECL presented evidence from a panel of witnesses, namely:

- Jason Roberts, President and Chief Executive Officer
- Michelle Francis, Vice President, Finance and Chief Financial Officer
- Angus Orford, Vice President, Corporate Planning and Energy Supply
- Enrique Riveroll, Vice President, Customer Service

17. Although PEIEC did not call any evidence at the hearing or question any of MECL's witnesses, PEIEC's legal counsel made a closing submission confirming PEIEC's agreement with all aspects of the GRA as filed by MECL and amended only by the Proposed Settlement. Although PEIEC's legal counsel advised that PEIEC had obtained two expert opinions, the opinions were not filed with the Commission or made publicly available by PEIEC.

18. The evidence filed with respect to the Application is extensive. The record includes more than 70 exhibits, including four expert reports. There was also a comprehensive pre-hearing interrogatory process. In total, the Commission, through its staff and expert witness, issued 106 interrogatories to MECL. MECL filed responses to all interrogatories in advance of the hearing.

19. All documents filed in this matter were provided to the parties. All non-confidential filings, including the expert reports, were made available to the public via the Commission website.

20. At the commencement of the public hearing, the parties filed an Affidavit on Negotiated Settlement as required by the Commission's *Rules of Negotiated Settlements*.[6] The sworn Affidavit is signed by both MECL and PEIEC and confirms, among other things, that MECL did not withhold any relevant information, all issues have been resolved, and all parties are in agreement with the Proposed Settlement.

21. The Commission has considered all of the evidence filed with respect to the Application in reaching the decision that follows.

COMMISSION'S AUTHORITY UNDER THE *ELECTRIC POWER ACT*:

22. The Commission is an independent, quasi-judicial tribunal. It exercises appellate, adjudicative, and regulatory authority under a number of provincial statutes, including the

[6] Exhibit M-16

Electric Power Act. In doing so, the Commission is required to follow legislative requirements and administrative law principles.

23. The *Electric Power Act* gives the Commission broad regulatory oversight over public utilities, including MECL. When MECL seeks to vary its rates for electric service, it must first apply to the Commission for approval. The Commission has the authority to approve the rates proposed by MECL, or to determine and fix new rates.[7] The electric rates set by the Commission are the lawful rates and the rates that MECL is permitted to charge its customers.[8]

24. As MECL is a regulated monopoly and can only charge the rates approved by the Commission, the rates set by the Commission must balance the interests of MECL and the interests of its customers. As a result, the Commission's ratemaking function is designed to allow MECL to recover its legitimate costs of providing service, and an opportunity to earn a return on investment, at rates that are fair and reasonable for its customers.

25. Negotiated settlements are commonly used in matters of electric utility regulation across Canada. They allow the parties to determine what matters are agreed upon and what matters are in contention. This can lead to a more efficient regulatory process, which benefits both the utility and its customers.

26. However, the Commission, as regulator, is not bound by any settlement agreement between the parties. Notwithstanding that a settlement has been reached, the Commission is required to review and evaluate the General Rate Application as a whole, and to set rates, tolls and charges for electric service that are reasonable, publicly justifiable and non-discriminatory.

27. The Commission's approach to settlement agreements was explained in Commission Order UE16-04R. The following principles bear repeating:

> *The Commission notes at the outset that it is not a party to the Agreement and does not consider itself to be, in any way, bound by the terms of the Agreement. The Commission's jurisdiction to regulate public utilities, including Maritime Electric, is founded in the EPA [Electric Power Act]. Although the Agreement is evidence that certain matters are supported by the Government, the Commission must still exercise its jurisdiction to set rates, tolls and charges for electric service that it determines to be reasonable, publicly justifiable, and non-discriminatory.*
>
> […]
>
> *Once the interested parties reach a negotiated settlement, the agreement is not simply approved by "rubber stamp" of the regulator. Instead, a regulator presented with a negotiated settlement is required to determine if the agreement is in the public interest (see Nova Scotia Power Inc. (Re), 2012*

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[7] *Electric Power Act*, section 20(1)
[8] *Electric Power Act*, section 20(2)

> *NSUARB 227 at para. 24). A settlement agreement does not replace an "appropriate and informed review by the Board as to what is in the overall public interest" (see ATCO Electric Ltd. v. Alberta (Energy and Utilities Board), 2004 ABCA 215 [ATCO] at para. 139).*[9]

28. The Commission has followed this approach in its review of this GRA and the Proposed Settlement.

DECISION:

29. Based on a review of all of the evidence, the Commission is satisfied that, for the most part, the Proposed Settlement represents an appropriate balance between the interests of MECL and the interests of its customers. It is also satisfied that the rates, tolls and charges set forth in the Proposed Settlement are, in the circumstances, reasonable and publicly justifiable.

30. The Commission does, however, have concerns about certain aspects of the Proposed Settlement, as will be discussed following. These concerns will be addressed through the requirement of further filings by MECL and review and investigation by the Commission, in accordance with the Commission's mandate and general power of supervision under the *Electric Power Act*.

Allowed ROE

31. In the Proposed Settlement, MECL has agreed to an ROE of 9.35 percent for the purpose of calculating its revenue requirement, and a maximum ROE of 9.7 percent for the purpose of calculating its annual earnings. This means that although an ROE of 9.35 was used to calculate customer rates, MECL will have the opportunity to earn an ROE of up to 9.7 percent through operating efficiencies and/or business growth.

32. The 9.7 percent "deadband" is not unlike the earnings sharing mechanisms that MECL has applied for in previous General Rate Applications. The Commission has consistently refused MECL's requests for an earnings sharing mechanism due to MECL's pattern of over-earning.[10]

33. The Commission has also expressed serious concerns about the impact that an earnings sharing mechanism will have on the rate of return adjustment ("RORA") account.[11] In the absence of an earnings sharing mechanism, savings associated with operational efficiencies and increased revenue associated with sales growth are refunded to ratepayers through the RORA account. The "deadband" that MECL and PEIEC have agreed to means that those financial benefits will now go to MECL, rather than to its customers. A RORA balance will not be recorded until MECL has achieved an ROE of 9.7 percent.

[9] Order UE16-04R at paras. 28, 32
[10] Order UE19-08 at paras. 124-126
[11] Order UE19-08 at para. 124

34. Despite the Commission's ongoing concerns, the Commission approves an ROE of 9.35 percent up to a maximum of 9.7 percent. The Commission is satisfied that a "deadband" is appropriate in these specific circumstances as the ROE for the purpose of calculating the revenue requirement is less than the ROE recommended by the expert witnesses, including the independent expert retained on behalf of the Commission. In addition, the maximum ROE for the purpose of calculating annual earnings (9.7 percent) is the lowest ROE recommended by the expert witnesses.

35. MECL should not assume that a deadband or earnings sharing mechanism will be approved in any other circumstances or in future rate applications.

36. As part of the Proposed Settlement, MECL has committed to achieving the allowed maximum ROE by "*effectively managing the business and/or finding cost efficiencies that are neutral or beneficial to rate payers*".[12] MECL has specifically agreed that it will not decrease its vegetation management costs in order to achieve the maximum ROE.

37. The Commission accepts these parameters as being appropriate and in the best interest of ratepayers. MECL is required to report to the Commission, on an annual basis, the ROE actually earned, together with a complete accounting of the management decisions and/or cost efficiencies that contributed to earnings above 9.35 percent, and an explanation of how the management decisions and/or cost efficiencies are neutral or beneficial to ratepayers.

Vegetation Management

38. The GRA was filed in June 2022, before the Province was impacted by Post-Tropical Storm Fiona ("Fiona") in September 2022. Fiona caused extensive damage to MECL's transmission and distribution systems. The restoration efforts cost approximately $35 million and it took MECL approximately three weeks to restore power to all customers. According to MECL, the majority of the damage was caused by tree contacts.

39. MECL was aware – prior to Fiona – that its vegetation management plan was inadequate and was contributing to system outages during major events.[13] In 2019, MECL completed a vegetation inspection of all of its off-road transmission system and almost half of its roadside transmission and distribution systems. Based on the results of this inspection, MECL estimated that 60,600 distribution spans and 6,400 transmission spans required "*urgent vegetation management to avoid a significant deterioration of reliability*".[14]

40. In the GRA as filed, MECL advised that its current vegetation management cycle results in a 35 year cycle for distribution lines and a 14 year cycle for transmission lines.[15] This is substantially higher than the vegetation management cycles used by other utilities in Atlantic Canada. By comparison, New Brunswick Power's distribution vegetation management cycle is 5 to 7 years, while Nova Scotia Power follows an 8 year cycle.[16]

[12] Exhibit M-14 at page 2
[13] Exhibit M-1 at pages 24-25
[14] Exhibit M-1, Appendix E, page 5, lines 11-14
[15] Exhibit M-1, Appendix E, page 4, lines 13-14
[16] Exhibit M-1, Appendix E, page 4, Table E-1

According to MECL, "*good utility practice recommends a vegetation management cycle of five to ten years*".[17]

41. In the GRA, MECL set out options that it considered to improve its current vegetation management cycle.[18] A target vegetation management cycle of 6 years for the distribution system would require an annual budget of $8.1 million. As MECL currently budgets only $1.4 million for distribution vegetation management, it determined that an annual increase of $6.7 million would be "*too high for customers*".[19]

42. Instead, MECL has proposed to increase the annual budget by $700,000 annually until it reaches $4 million in 2025. This means that by 2025, MECL's vegetation management cycle will be 14 years for the distribution system and 9 years for the transmission system. PEIEC agreed to this vegetation management plan as part of the Proposed Settlement.

43. However, due to the increasing severity and frequency of major weather events, the Commission has serious concerns about the vegetation management plan and the impact on system reliability. MECL is required, by virtue of the *Electric Power Act*, to provide safe and adequate service "*as changing conditions require*".[20] Severe weather events, such as Fiona, are a changing condition under which MECL must operate, and its operational and capital plans must be updated to reflect these conditions.

44. The Commission requires additional information from MECL as to the current state of its vegetation management program, particularly in the wake of Post-Tropical Storm Fiona, to assess the sufficiency of current and planned expenditures. As a result, MECL must file a comprehensive report with the Commission, no later than December 1, 2023, that identifies areas of risk for reliability and that clearly details MECL's short-term and long-term plans (both operating and capital) for vegetation management, including the forecast improvements in vegetation management and reliability.

Energy Cost Adjustment Mechanism

45. The Energy Cost Adjustment Mechanism ("ECAM") is a regulatory deferral account approved by the Commission. The ECAM is used to defer unplanned fluctuations in energy supply costs that occur in a rate setting period. Prudently incurred energy supply costs that exceed the forecast cost are recorded to ECAM and recovered from ratepayers as directed by the Commission.

46. MECL incurred higher than forecast energy supply costs in 2022 due, primarily, to unscheduled outages at Point Lepreau. The increase in purchased and produced electricity costs were appropriately deferred to the ECAM account for future collection from ratepayers.

47. The rates proposed by MECL in the GRA and in the Proposed Settlement assumed that the ECAM balance would be approximately $6.791 million as of December 31, 2022.

[17] Exhibit M-1, Appendix E, page 5, lines 2-4
[18] Exhibit M-1, Appendix E, page 6
[19] Exhibit M-1, Appendix E, page 6, lines 5-6
[20] *Electric Power Act*, section 3(a)

However, the actual ECAM balance as of December 31, 2022 was $11.655 million – $4.864 million higher than forecast. The Proposed Settlement agreed to by PEIEC does not include a plan to recover the difference between the forecast and actual ECAM balance.

48. The Commission has previously expressed concern with maintaining an ECAM balance.[21] An ECAM balance means that present-day ratepayers are not paying the full cost of the electricity they consume. This does not send the appropriate price signal to customers and is not consistent with the principle of intergenerational equity. In addition, MECL is entitled to earn a rate of return on the balance of the ECAM. This is not in the best interest of ratepayers.

49. Through the interrogatory process, MECL agreed that it is not appropriate to defer the outstanding ECAM balance to the next rate setting period.[22] Instead, MECL intends to file a separate application with the Commission in 2023 to seek recovery of the ECAM balance. This means that there will be another increase in electric rates – separate from the increase agreed to in the Proposed Settlement and approved in this Order.

50. Although the ECAM rate adjustment is not explicitly addressed in the Proposed Settlement, MECL has clearly stated its intention to file for a separate application to collect the outstanding ECAM balance. In the course of the public hearing, MECL advised that the application would be filed in a timely manner, and suggested that an ECAM rate adjustment could be effective September 2023 or March 2024.

51. PEIEC, through submissions made by its legal counsel at the public hearing, agreed with all submissions made by MECL. This is consistent with the sworn Affidavit on Negotiated Settlement which states that MECL did not withhold any relevant information and that the parties (PEIEC and MECL) were in agreement on all issues.[23] This would necessarily include MECL's express plan to file an ECAM rate adjustment separate and apart from this GRA.

52. MECL's proposal to deal with the outstanding ECAM balance in a separate rate adjustment application is, in the circumstances, reasonable. To ensure the collection of the ECAM balance is dealt with in a timely manner, MECL must file the ECAM rate adjustment application with the Commission no later than July 31, 2023 for an October 1, 2023 rate adjustment. Although this results in a short delay, the Commission agrees as it will allow for a comprehensive review of the ECAM account balance.

Weather Normalization Mechanism and Reserve Account

53. The Weather Normalization Mechanism and Reserve Account ("WNR") is a regulatory deferral account that, according to MECL, is used to stabilize electricity rates charged to customers by removing sales and energy supply cost volatility caused by temperature

[21] Order UE19-08 at paras. 155-157
[22] Exhibit M-15, page 19, Response to IR-56
[23] Exhibit M-16

changes. The mechanism operates by allowing MECL to "reserve" revenue earned in colder-than-average years for use in warmer-than-average years.

54. The WNR has been approved on an interim basis since 2016.[24] From the outset, the Commission expressed concerns about the WNR, including that it would effectively decrease the over-earnings that are refunded to ratepayers through the RORA account. Due to these concerns, the WNR has only ever been approved on an interim basis.

55. In the GRA as filed, MECL sought to have the WNR approved on a permanent basis. According to MECL, the increased penetration of electric space heating over the last 10 years has introduced greater sales volatility from variations in heating degree days ("HDD") compared to the 10 year average. The WNR is intended to mitigate the risk to MECL of sales volatility due to variations in temperature.

56. According to MECL, because the variable for HDD is based on a 10 year average, over a 10 year period, the variations from HDD balances – and the balance of the WNR – should trend to zero. However, this has not been the case.

57. When the GRA was filed in June 2022, the balance of the WNR stood at $1.8 million receivable from customers. MECL acknowledged that the receivable balance accumulated over a relatively short period of 13 months.[25] By December 31, 2022, the balance of the WNR had grown to $3.2 million receivable from customers.

58. In the Proposed Settlement, MECL acknowledges the Commission's concerns and proposes that the WNR continue on an interim basis during the rate setting period. MECL also proposes to undertake a comprehensive review of the WNR, prior to submitting its next General Rate Application, to support approval of the WNR on a permanent basis. PEIEC agreed with this approach as part of the Proposed Settlement.[26]

59. The Commission continues to have serious concerns about the WNR. These concerns are compounded by the growing balance of the WNR owed by ratepayers to MECL.

60. The WNR has now been approved on an interim basis for 7 years. MECL maintains that the function of the WNR should be considered over a 10 year cycle. At the end of 10 years, the annual variations should net to average and the balance of the WNR should be zero.[27]

61. In light of this evidence, the Commission is prepared to allow the WNR to continue on an interim basis only during the rate setting period or until the Commission orders otherwise after receipt of the comprehensive report referred to below. At the conclusion of the rate setting period (2026), the WNR will have been in effect for 10 years and – according to MECL – the balance should average to zero. However, the Commission is concerned that the balance of the WNR is trending upward at a rapid pace.

[24] Orders UE16-04 and UE16-04R
[25] Exhibit M-1, page 84
[26] Exhibit M-14, page 7
[27] Exhibit M-15, page 8, Response to IR-47

62. The idea of "capping" the balance of the WNR was put to MECL in the course of the public hearing. MECL acknowledged that although it expects the balance of the WNR to net to zero, a cap could be put in to place to provide reassurance to the Commission. MECL's preference is that the WNR not be capped, and that a cap be further explored as part of a comprehensive review of the WNR.

63. Although a further review of the WNR is warranted, if the balance of the WNR is not capped now, there is a real risk to customers that the balance owed by customers to MECL will increase over the course of the rate setting period.

64. As a result, the WNR shall be capped such that the amount recorded in rate base, and the amount recovered from or refunded to ratepayers at a future date, shall not exceed the balance of the WNR as of April 30, 2023. This should not have a material impact on MECL for at least two reasons: (1) MECL is not seeking to recover the WNR balance from ratepayers during the rate setting period, and (2) according to MECL's own evidence, the balance of the WNR should average to zero (i.e. decrease) by 2026.

65. MECL must also undertake a comprehensive review of the WNR prior to filing its next General Rate Application. The comprehensive review must (among other things) fully explain other weather normalization mechanisms approved by regulators across Canada, and how those mechanisms compare or differ from MECL's approved WNR. The review must include consideration of cooling degree days and whether cooling degree days should properly form part of the WNR. The comprehensive review must be filed on or before January 31, 2024.

General Rules & Regulations

66. MECL's General Rules and Regulations ("GRR") relate to the kind of service supplied to customers and the manner by which that service is supplied.[28] In addition to the rates for electric service, the GRR deal with matters such as security deposits, billing and payment requirements, disconnections initiated by MECL, and customer contributions for line extensions. Often, customer complaints made to the Commission have to do with the interpretation and application of the GRR.

67. In recent years, Canadian utilities and regulators have undertaken comprehensive reviews of the rules governing the provision of service. The Commission directs MECL to likewise undertake a comprehensive review of its GRR. The comprehensive review should compare and contrast similar Rules used by other Canadian regulators and utilities, with a specific emphasis on consumer safeguards that are not currently available in MECL's GRR.

68. The comprehensive review of the GRR shall be filed with the Commission on or before January 31, 2025. Any changes to the GRR approved by the Commission will take effect in the next rate setting period.

[28] *Electric Power Act*, section 13(1)

Depreciation & Amortization

69. In July 2021, MECL filed a depreciation study based on financial results ending December 31, 2020 (the "2020 Depreciation Study").[29] The authors of the 2020 Depreciation Study, Gannett Fleming, noted that MECL's actual retirement costs "*are trending much higher than contemplated in previous depreciation studies*".[30] Further analysis by Gannett Fleming "*resulted in net salvage percentages that are considered abnormally high*". Gannett Fleming determined that further analysis of the general expense retirement account is warranted.

70. In response to interrogatories issued by the Commission, MECL advised that additional analysis of the general expense retirement account has not yet been completed.[31]

71. MECL is directed to undertake the additional analysis of the general expense retirement account recommended by Gannett Fleming. This analysis will form part of the next depreciation study, which is to be filed with the Commission on or before June 30, 2024, based on financial results to December 31, 2023.

<u>ORDER:</u>

For the foregoing reasons, the Commission Orders as follows:

Electric Rates

1. The Commission approves the rates, tolls and charges for electric service as set out in the Schedule of Rates attached as Appendix "A" to this Order.

2. The rates approved herein shall be effective as of May 1, 2023, and shall remain in effect until February 28, 2026, or until otherwise varied by the Commission.

General Rules & Regulations

3. MECL's General Rules and Regulations ("GRR") shall be amended to incorporate the terms of this Order.

4. The amended GRR shall be filed with the Commission on or before May 15, 2023.

5. MECL shall undertake a comprehensive review of its GRR. The comprehensive review shall (among other things) compare and contrast similar Rules used by other Canadian regulators and utilities, with a specific emphasis on consumer safeguards that are not currently available in MECL's GRR.

6. The comprehensive review of the GRR shall be filed with the Commission by January 31, 2025, and any changes to the GRR approved by the Commission shall take effect in the next rate setting period.

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[29] Exhibit M-1(c)
[30] Exhibit M-1(c) at pages IV-4 to IV-5
[31] Exhibit M-7, page 68, Response to IR-44(a)

Return on Equity

7. The ROE used in the calculation of the revenue requirement shall be 9.35 percent based on 40 percent average common equity in each of 2023, 2024 and 2025, or until otherwise varied by the Commission.

8. The maximum allowed ROE used in the calculation of earnings shall be 9.7 percent in each of 2023, 2024 and 2025, or until otherwise varied by the Commission.

9. MECL shall be permitted to achieve the maximum allowed ROE of 9.7 percent through management decisions and/or cost efficiencies that are neutral or beneficial to ratepayers.

10. MECL shall not be permitted to decrease its vegetation management costs to achieve the maximum allowed ROE.

11. MECL shall file with the Commission, no later than February 28th in each year of the rate setting period, a report that contains:

    a) the ROE actually earned by MECL in the preceding year;

    b) a complete accounting of the management decisions and/or cost efficiencies that contributed to any earnings above 9.35 percent; and

    c) an explanation of how the management decisions and/or cost efficiencies are neutral or beneficial to ratepayers.

Rate of Return Adjustment

12. If MECL's earnings exceed 9.7 percent based on 40 percent common equity in any year of the rate setting period, the excess earnings shall be recorded to a separate RORA account specifically for over-earnings accumulated during the period from January 1, 2023 to February 28, 2026.

13. The balance of the RORA account (if any) as of December 31st in each year of the rate setting period shall be refunded to ratepayers as directed by the Commission.

14. MECL shall continue to report the balance of the RORA account to the Commission on a monthly and annual basis.

Energy Cost Adjustment Mechanism

15. The ECAM base rate per kWh shall be as follows:

    $0.09050 for the period May 1, 2023 to February 29, 2024;

    $0.09440 for the period March 1, 2024 to February 28, 2025; and

    $0.09612 for the period March 1, 2025 to February 28, 2026.

16. The ECAM collection rate per kWh shall be as follows:

    $0.00589 for the period May 1, 2023 to February 29, 2024;

$0.00287 for the period March 1, 2024 to February 28, 2025; and

$0.00145 for the period March 1, 2025 to February 28, 2026.

17. MECL shall file its ECAM rate adjustment application with the Commission no later than July 31, 2023 for an October 1, 2023 rate adjustment.

Weather Normalization Mechanism and Reserve Account

18. The Weather Normalization Mechanism and Reserve Account ("WNR") is approved on an interim basis only until February 28, 2026 or until otherwise ordered by the Commission.

19. The balance of the WNR shall be capped such that the amount recorded in rate base, and the amount recovered from or refunded to ratepayers at a future date, shall not exceed the balance of the WNR as of April 30, 2023.

20. MECL shall undertake a comprehensive review of the WNR that (among other things):

    a) fully explains other weather normalization mechanisms approved by regulators across Canada, and how those mechanisms compare or differ from MECL's approved WNR; and

    b) includes consideration of cooling degree days and whether cooling degree days should properly form part of the WNR.

21. The comprehensive review shall be filed with the Commission on or before January 31, 2024.

Revenue Shortfall and RORA Refund

22. The forecast over-refund of the RORA account as of April 30, 2023 ($223,338) shall be offset against the forecast over-collection of the 2020 revenue shortfall account as of April 30, 2023 ($2,472,248), and the forecast net amount ($2,248,910) shall be refunded to ratepayers as a rate rider set at $0.00195 per kWh from May 1, 2023 to February 29, 2024.

23. On or before April 15, 2024, MECL shall report to the Commission the amount refunded to ratepayers as of February 29, 2024. Any amount over or under-refunded as of February 29, 2024 shall be addressed by further Order of the Commission.

Provincial Debt Repayment

24. Costs recoverable from ratepayers on behalf of the Province of Prince Edward Island related to debt repayment costs shall no longer be collected as a rate rider and shall instead be included in the revenue requirement and collected during the period May 1, 2023 to February 28, 2026.

Recovery of EE&C Plan Costs

25. MECL shall collect from ratepayers, and remit to PEIEC, the following amounts as contribution to the Energy Efficiency and Conservation Plan ("EE&C Plan") costs:

2023/2024: $868,000

2024/2025: $868,000

2025/2026: $1,732,000

26. MECL shall collect the EE&C Plan costs as a per kWh rate rider at the following rates:

$0.00000 for the period May 1, 2023 to February 29, 2024;

$0.00033 for the period March 1, 2024 to February 28, 2025; and

$0.00121 for the period March 1, 2025 to February 28, 2026.

27. MECL shall remit the annual EE&C Plan costs to PEIEC in fixed monthly amounts. Any over or under-collections shall be held in a separate account, the balance of which shall be reported to the Commission on a monthly and annual basis.

28. The annual EE&C Plan costs set forth in this Order may be varied by the Commission in Docket UE41401 (PEIEC EE&C Plan Application), in which case the rate riders approved herein shall be varied accordingly.

Vegetation Management

29. MECL shall file, no later than December 1, 2023, a comprehensive report with the Commission that identifies areas of risk for reliability and that clearly details MECL's short-term and long-term plans (both operating and capital) for vegetation management, including the forecast improvements in vegetation management and reliability.

Deprecation & Amortization

30. MECL shall adopt the depreciation rates recommended in the 2020 Depreciation Study effective as of January 1, 2023, with the exception of the rates pertaining to the Charlottetown Steam Plant.

31. The Charlottetown Thermal Generating Station Reserve Variance deferral shall be amortized as part of MECL's annual revenue requirement from January 1, 2023 to December 31, 2027.

32. On or before June 30, 2024, MECL shall file with the Commission an updated depreciation study based on financial results to December 31, 2023 (the "2023 Depreciation Study").

33. MECL shall undertake additional analysis of the general expense retirement account recommended in the 2020 Depreciation Study for inclusion in the 2023 Depreciation Study.

Reporting Requirements

34. In addition to the reporting requirements in this Order, MECL shall continue to file its usual monthly and annual reports with the Commission without change.

DATED at Charlottetown, Prince Edward Island, this 24th day of April, 2023.

BY THE COMMISSION:

(sgd) J. Scott MacKenzie

J. Scott MacKenzie, K.C., Chair

(sgd) M. Douglas Clow

M. Douglas Clow, Vice-Chair

(sgd) Erin T. Mitchell

Erin T. Mitchell, Commissioner

Appendix A

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		March 1, 2022	May 1, 2023	March 1, 2024	March 1, 2025
110	**Residential**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1593	$ 0.1634	$ 0.1690
	Energy Charge per kWh for balance kWh	$ 0.1228	$ 0.1268	$ 0.1299	$ 0.1342
130	**Residential Rural**				
	Service Charge	$ 26.92	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1593	$ 0.1634	$ 0.1690
	Energy Charge per kWh for balance kWh	$ 0.1228	$ 0.1268	$ 0.1299	$ 0.1342
131	**Residential Seasonal**				
	Service Charge	$ 26.92	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1593	$ 0.1634	$ 0.1690
	Energy Charge per kWh for balance of kWh	$ 0.1228	$ 0.1268	$ 0.1299	$ 0.1342
133	**Residential Seasonal Option**				
	Service Charge	$ 37.50	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1532	$ 0.1593	$ 0.1634	$ 0.1690
	Energy Charge per kWh for balance of kWh	$ 0.1228	$ 0.1268	$ 0.1299	$ 0.1342
232	**General Service**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1871	$ 0.1958	$ 0.2010	$ 0.2080
	Energy Charge per kWh for balance of kWh	$ 0.1241	$ 0.1282	$ 0.1313	$ 0.1356
233	**General Service - Seasonal Operators Option**				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1871	$ 0.1958	$ 0.2010	$ 0.2080
	Energy Charge per kWh for balance of kWh	$ 0.1241	$ 0.1282	$ 0.1313	$ 0.1356
320	**Small Industrial**				
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1834	$ 0.1917	$ 0.1968	$ 0.2036
	Energy Charge per kWh for balance of kWh	$ 0.0950	$ 0.0970	$ 0.0991	$ 0.1022
310	**Large Industrial**				
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0780	$ 0.0809	$ 0.0829	$ 0.0857
340	**Long Term Contract** (Currently no customers in this rate category)				
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.1044	$ 0.1041	$ 0.1065	$ 0.1132
330	**Short Term Contract** (Currently no customers in this rate category)				
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.1036	$ 0.1062	$ 0.1087	$ 0.1121
	Energy Charge per kWh for balance of kWh in the month	$ 0.0869	$ 0.0882	$ 0.0901	$ 0.0928

Appendix A

Maritime Electric Company, Limited
Schedule of Rates

	Residential	Type		Annual kWh	Monthly kWh	March 1, 2022	May 1, 2023	March 1, 2024	March 1, 2025
	619	LED	70 W HPS Equivalent St Lights - Rented		15	$ 12.49	$ 12.81	$ 13.14	$ 13.49
	625	LED	100 W HPS Equivalent St Lights - Rented		17	$ 12.93	$ 13.26	$ 13.60	$ 13.97
*	630	HPS	St Lights - Rented	389	32	$ 16.57	$ 17.00	$ 17.44	$ 17.91
*	631	HPS	St Lights - Rented	553	46	$ 21.06	$ 21.61	$ 22.17	$ 22.77
*	632	150	St Lights - Rented	799	66	$ 30.12	$ 30.90	$ 31.70	$ 32.56
	633	HPS	St Lights - Rented	1283	106	$ 41.02	$ 42.08	$ 43.17	$ 44.34
	634	HPS	St Lights - Rented	1886	157	$ 48.10	$ 49.35	$ 50.63	$ 52.00
*	635	MV	St Lights - Rented	656	54	$ 16.50	$ 16.93	$ 17.37	$ 17.84
	639	Lanterns	City Lanterns - Rented	389	32	$ 60.56	$ 62.13	$ 63.75	$ 65.47
*	640	HPS	St Lights - Owned	389	32	$ 6.59	$ 6.76	$ 6.94	$ 7.13
*	641	HPS	St Lights - Owned	553	46	$ 8.70	$ 8.93	$ 9.16	$ 9.41
*	642	HPS	St Lights - Owned	779	65	$ 11.70	$ 12.01	$ 12.32	$ 12.65
	643	HPS	St Lights - Owned	1283	107	$ 18.56	$ 19.04	$ 19.54	$ 20.07
	644	HPS	St Lights - Owned	1886	157	$ 29.22	$ 29.98	$ 30.76	$ 31.59
	666	LED	175 W MV Equivalent St Lights - Rented		25	$ 14.41	$ 14.78	$ 15.16	$ 15.57
	670	LED	St Lights - Rented	410	34	$ 16.78	$ 17.21	$ 17.66	$ 18.14
	675	LED	150 W/200 W HPS Equivalent St Lights - Rented		37	$ 15.61	$ 16.01	$ 16.43	$ 16.87
	719	LED	St Lights - Owned	176	15	$ 2.69	$ 2.76	$ 2.83	$ 2.91
*	730	HPS	Yard Lights - Rented	389	32	$ 16.57	$ 17.00	$ 17.44	$ 17.91
*	731	HPS	Yard Lights - Rented	553	46	$ 21.06	$ 21.61	$ 22.17	$ 22.77
*	732	HPS	Yard Lights - Rented	799	66	$ 30.12	$ 30.90	$ 31.70	$ 32.56
	733	HPS	Yard Lights - Rented	1283	106	$ 41.02	$ 42.08	$ 43.17	$ 44.34
	734	HPS	Yard Lights - Rented	1886	157	$ 48.10	$ 49.35	$ 50.63	$ 52.00
*	735	MV	Yard Lights - Rented	656	54	$ 16.50	$ 16.93	$ 17.37	$ 17.84
*	736	MV	Yard Lights - Rented	881	73	$ 20.98	$ 21.53	$ 22.09	$ 22.69
*	737	MV	Yard Lights - Rented	1210	100	$ 29.19	$ 29.95	$ 30.73	$ 31.56
*	740	HPS	Yard Lights - Owned	389	32	$ 6.59	$ 6.76	$ 6.94	$ 7.13
*	741	HPS	Yard Lights - Owned	553	46	$ 8.70	$ 8.93	$ 9.16	$ 9.41
	742	HPS	Yard Lights - Owned	779	65	$ 11.70	$ 12.01	$ 12.32	$ 12.65
	743	HPS	Yard Lights - Owned	1283	107	$ 18.56	$ 19.04	$ 19.54	$ 20.07
	744	HPS	Yard Lights - Owned	1886	157	$ 29.22	$ 29.98	$ 30.76	$ 31.59
	749	LPS	Yard Lights - Owned	869	72	$ 13.63	$ 13.98	$ 14.34	$ 14.73
	753	Flood	Yard Lights - Rented	1283	107	$ 39.16	$ 40.18	$ 41.22	$ 42.33
	754	Flood	Yard Lights - Rented	1886	157	$ 48.84	$ 50.11	$ 51.41	$ 52.80
	755	Halide	Yard Lights - Rented	1148	95	$ 41.17	$ 42.24	$ 43.34	$ 44.51
	756	Halide	Yard Lights - Rented	1878	156	$ 50.83	$ 52.15	$ 53.51	$ 54.95
	757	Halide	Yard Lights - Rented	4346	362	$ 87.62	$ 89.89	$ 92.23	$ 94.72
	759	Halide	St Lights - Owned	533	44	$ 8.14	$ 8.35	$ 8.57	$ 8.80
	760	Halide	St Lights - Owned	894	74	$ 13.67	$ 14.02	$ 14.38	$ 14.77
	761	Halide	St Lights - Owned	1148	95	$ 17.53	$ 17.99	$ 18.46	$ 18.96
	762	Halide	St Lights - Owned	1878	156	$ 28.67	$ 29.41	$ 30.17	$ 30.98
	764	LED	St Lights - Owned	410	34	$ 6.26	$ 6.42	$ 6.59	$ 6.77
	765	Halide	St Lights - Owned	759	63	$ 11.58	$ 11.88	$ 12.19	$ 12.52
	766	LED	St Lights - Owned	295	25	$ 4.50	$ 4.62	$ 4.74	$ 4.87
	775	LED	St Lights - Owned	438	37	$ 6.69	$ 6.86	$ 7.04	$ 7.23
	780	LED	St Lights - Owned	586	49	$ 8.95	$ 9.18	$ 9.42	$ 9.67
	785	LED	St Lights - Owned	718	60	$ 10.94	$ 11.22	$ 11.51	$ 11.82

* These charges are applicable to existing fixtures only.

Appendix A

Maritime Electric Company, Limited

Schedule of Rates

		March 1, 2022	May 1, 2023	March 1, 2024	March 1, 2025
610	Pole Rental -Wood	$ 4.38	$ 4.38	$ 4.38	$ 4.38
	Residential				
	Unmetered Rates (based on 100 watt fixture)				
810	8 Hour Lighting per kWh	$ 0.1830	$ 0.1913	$ 0.1964	$ 0.2032
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
820	12 Hour Lighting per kWh	$ 0.1830	$ 0.1913	$ 0.1964	$ 0.2032
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1830	$ 0.1830	$ 0.1964	$ 0.2032
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67	$ 11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category			
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week				
234	Customer Owned Outdoor Recreational Lighting				
	Service Charge	$ 24.57	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.1830	$ 0.1830	$ 0.1964	$ 0.2032
	Energy Charge per kWh for balance of kWh	$ 0.1139	$ 0.1171	$ 0.1198	$ 0.1237
	Short Term Unmetered Rates	Currently no customers in this rate category			
	Energy Charge:				
	per kWh of estimated consumption	$ 0.1830	$ 0.1830	$ 0.1964	$ 0.2032

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	0	$594.94

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British Columbia Utilities Commission

Generic Cost of Capital Proceeding

(Stage 1)

Decision
and Order G-236-23

September 5, 2023

Before:
D. M. Morton, Panel Chair
A. K. Fung, KC, Commissioner
K. A. Keilty, Commissioner
T. A. Loski, Commissioner

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EXECUTIVE SUMMARY

The British Columbia Utilities Commission (BCUC), pursuant to section 59(5)(b) of the *Utilities Commission Act* (UCA) is responsible for ensuring that shareholders of the utilities it regulates are afforded a reasonable opportunity to earn a fair return on their invested capital.

On January 18, 2021, the BCUC noted that significant time had passed since the BCUC's 2013 and 2016 cost of capital reviews and over that period, changes have occurred in financial markets, and pursuant to section 82 of the UCA, issued a Notice of Initiating a Generic Cost of Capital (GCOC) Proceeding.

The BCUC determined that a two-stage proceeding to establish public utilities' cost of capital was appropriate for the GCOC proceeding. Stage 1 of the GCOC proceeding will determine the deemed capital structure and allowed return on equity (ROE) of FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC). Stage 2 will determine matters related to the benchmark utility, including whether utilizing a benchmark utility remains an appropriate approach and, if so, whether one or both or neither of these utilities should serve as a benchmark for establishing the cost of capital for other utilities in British Columbia (BC).

FEI and FBC jointly engaged Mr. James Coyne (Mr. Coyne) of Concentric Energy Advisors Inc. (Concentric) as their expert consultant in Stage 1 of the GCOC proceeding. The BCUC engaged Dr. Jonathan A. Lesser (Dr. Lesser) of Continental Economics, Inc. (Continental Economics) as an independent expert. Dr. Lesser opined on Mr. Coyne's expert analysis. Dr. Lesser did not perform his own independent calculations and did not present capital structure or ROE recommendations. No Intervener engaged an expert to provide expert evidence on FortisBC's cost of capital.[1]

Key Principles

The purpose of Stage 1 of the GCOC proceeding is to set a fair return for FEI and FBC. When determining the utilities' cost of capital, the Panel is guided by certain fundamental regulatory principles, including the Fair Return Standard which requires three elements to be met for a fair and reasonable return on capital:

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.

In the BCUC's application of the Fair Return Standard, the utility must also be assessed based on the standalone principle. That principle 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

[1] Corix Multi-Utility Service Inc., Pacific Northern Gas Ltd and Pacific Northern Gas (N.E.) submitted a Brattle Report on the use of a Benchmark Utility (Exhibits B6-4 and B9-5).

company structure. The BCUC had noted the relevance of the standalone principle in past cost of capital decisions, and we continue to adhere to this principle to determine FEI and FBC's cost of capital in this proceeding.

Informed judgment, with the support of quantitative and qualitative evidence made available to us during the proceeding, plays a significant role in determining the appropriate cost of capital for each of the two utilities. Therefore, by necessity, certain aspects of our decision are as much art as science.

Approach to the Cost of Capital Determination

When determining the cost of capital and the allowable return, there are four key elements that the Panel considers:

1. The actual returns of a proxy group of peer utilities.
2. The business risks facing FEI and FBC, including how those risks may have changed since the last time the BCUC approved a cost of capital for those companies.
3. The credit ratings of FEI and FBC.
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.

Not one of the above elements is, in itself, determinative. Rather, the Panel considers all of these elements together, applying an appropriate weight to each of them as it determines the allowed cost of capital.

The Panel also makes determinations on "adders" to the ROE as applied for by FortisBC to account for flotation costs incurred by the parent company and for the need for "financial flexibility", again based on consideration of the above elements.

Consideration of Peer Data Set

To provide appropriate comparators for the allowed ROE and capital structure for FEI and FBC, the Panel determined a "proxy group" of peer companies that are both publicly traded and comparable to FEI and FBC's business and financial characteristics in order to assess each company's data. FortisBC and its expert, Mr. Coyne, presented proxy group data from both United States (US) and Canadian gas utilities and also combined these US and Canadian utilities into a North American proxy group. We agree with Mr. Coyne that some of the companies in his Canadian proxy group would not pass the same screening criteria he applied to his US proxy groups. The Panel finds merit in using a combined North American proxy group and removing certain non-qualifying Canadian utilities.

The Panel was presented with three sets of data during the proceeding, starting with December 2021 data when FortisBC filed its evidence and last updated in October 2022. The Panel is persuaded about the reasonableness of using the October 2022 market data, being the most recent publicly available data, to inform its establishment of an appropriate cost of capital.

Business Risks and Credit Ratings

Given the impact of business risk on utilities' expected return, the Panel reviews this from the perspective of the shareholder, as it is an important consideration for investors when making their investment decisions. Part of this review includes investors' consideration of credit ratings and changes in business risks.

Overall, the Panel finds that FEI's overall business risk to the shareholder has increased since 2016 while FBC's business risk has not changed materially for the shareholder since 2013. However, the Panel considers FEI and FBC's current credit ratings satisfactory for maintaining the financial integrity of each respective utility and that FEI and FBC do not require an improvement in those credit ratings for each utility to continue to attract capital on reasonable terms.

Financial Models

Regulators typically rely on financial models in their determination of an approved ROE because the actual cost of equity for a regulated utility cannot be observed. All models are simplifications of reality, using simplifying assumptions and as such, each model is subject to varying degrees of criticism. Quantitative models produce a range of reasonable results from which the ROE is selected.

The Panel considers three financial models:

1. The Capital Asset Pricing Model (CAPM), based on the relationship between non-diversifiable risk and expected return;
2. The Discounted Cash Flow (DCF), based on the premise that today's stock price represents investors' expectations regarding future cash flows from holding that stock, in terms of dividends and price appreciation; and
3. The Risk Premium Model, based on the premise that common equity capital is riskier than debt and, therefore, equity investors require a greater return than would debtholders.

For the CAPM, Mr. Coyne and Dr. Lesser have different opinions on how to estimate the key variables of risk-free rate and market risk premium (MRP), as well as the data sources for the beta coefficients, a measure of the risk of a security relative to the market. After examining the evidence and considering the views of the experts, we determine that Mr. Coyne's estimated risk-free rate based on forecast long-term government bond yields is reasonable, his data sources and averaging of adjusted data to estimate betas are acceptable, and his method to forecast the MRP, including a 50:50 weighting of historic and forward MRPs, sufficiently balances and moderates the assumption of higher analyst expectations over the next five years with the actual achieved MRPs over a long history. As a result, we are not relying on the CAPM results based on Mr. Coyne's interpretation of Dr. Lesser's preferred approach.

The Panel uses a CAPM ROE, exclusive of an adder for flotation costs and financial flexibility, of 9.90 percent for FEI and 9.77 percent for FBC, respectively, after removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group, as it weights the results of the different ROE models in the overall determination.

For the DCF model, Mr. Coyne presented two versions of the model: a constant DCF model and a Multi-Stage DCF model, consisting of three stages. Mr. Coyne only uses the latter's results in his ROE recommendations. Both experts agree on the merits of using the Multi-Stage DCF model. Consistent with the BCUC's preferred approach in the last two GCOC proceedings, the Panel finds that a Multi-Stage DCF model is preferable to a Constant Growth DCF model because the former allows for recognition that the proxy utility companies' dividend growth rates may not perform the same in different time horizons. Also, since no interveners commented on the pros and cons of using a two-stage versus a three-stage DCF model and most of them supported the three-stage DCF model presented by Mr. Coyne, the Panel finds it reasonable to use a three-stage DCF model to estimate the ROE for FEI and FBC, with each of the first two stages lasting five years.

Furthermore, both experts are aligned on key aspects of the multi-stage DCF analysis such as using recent average stock prices to calculate the dividend yield, forecast growth in earnings rather than dividend growth rates, and analysts' estimates for forecast earning growth rates. However, the two experts disagree on the data sources for the dividend growth rates in the first and third stage. After examining the evidence and considering the views of the experts, the Panel finds that using multiple sources for the analysts' forecasts of earnings growth rates is better than using a single source, as averaging can mitigate the impact of any one forecast. In the third stage, the Panel finds that using the gross domestic product (GDP) price deflator would be better than using consumer price index (CPI) to derive nominal GDP growth rates because the GDP price deflator is more representative of the market as a whole than CPI. However, as no evidence was presented using the GDP deflator, the Panel reluctantly accepts the use of CPI as a reasonable forecast to be used in the determination of long-term growth rates, while noting that the use of CPI may result in an overstated ROE. In the end, the Panel accepts Dr. Lesser's submission that the difference between the two would likely not be determinative in setting the ROE. As for the second (transition) stage, the Panel accepts the methodology employed by Mr. Coyne to transition between the first stage and the third stage growth rates.

The Panel uses a multi-stage DCF ROE, exclusive of an adder for flotation costs and financial flexibility, of 8.93 percent for FEI and 8.99 percent for FBC, respectively, after removing Enbridge Inc. and Canadian Utilities Limited from the North American proxy groups, as it weights the results of the different ROE models in the overall determination.

In the Panel's view, relying on more models is especially important at times when the pure market-based models like the DCF and the CAPM tend to get whipsawed by volatility in the market. The Panel finds that considerable weight should be given to the use of a Risk Premium Model for the purposes of determining the appropriate ROE for FEI and FBC given the recent volatility in the market and economic conditions.

The Panel notes that the Federal Energy Regulatory Commission has recognized the theoretical validity and value of the Risk Premium Model, as it has adopted that model along with the CAPM and DCF models, which it weights equally for determining the cost of capital for regulated electric transmission companies in the US. The Panel uses a Risk Premium Model ROE of 10.12 percent for FEI and 10.16 percent for FBC, respectively, as it weights the different ROE models in the overall determination.

Ultimately, the Panel finds that assigning an equal weighting to each of the three financial models is appropriate to determine the approved ROE for FEI and FBC.

Overall Determinations

The Panel finds that the appropriate way to account for required financial flexibility is in the context of determining the appropriate capital structure.

The Panel accepts that any reasonable and prudently incurred flotation costs incurred by a public utility are recoverable from ratepayers, over and above the approved costs of capital. However, there is no evidence before the Panel that FEI or FBC incurs any flotation costs and therefore there are no costs to recover. FEI and FBC can request recovery of actual costs incurred by the parent company by providing applicable invoices or other supporting documentation from the parent when FEI and FBC issue additional equity. Those expenditures, if and as incurred, can be considered for recovery from the ratepayers of FEI or FBC through review and approval as part of each utility's revenue requirement process.

The Panel finds that 45.0 percent equity thickness for FEI meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by the Panel's assessment of FEI's business risk.

The Panel finds that a modest upward adjustment of 1.0 percent for financial leverage and flexibility for FBC is warranted to conform with the Fair Return Standard. The Panel determines that the deemed equity component for FBC is 41.0 percent.

Based on the evidence examined and submissions received in Stage 1 of the GCOC proceeding, the Panel determines the following equity component in the deemed capital structure and allowed ROE will meet the Fair Return Standard:

- For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and
- For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.

Effective Date

The Panel determines that the deemed capital structure and allowed ROE for FEI and FBC as set out in this decision be implemented, effective January 1, 2023. Each of FEI and FBC is directed to file, within 30 days of the date of this decision, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved.

FEI is the current benchmark (Benchmark Utility) for other utilities in BC that use a Benchmark Utility to set their rates. The Panel notes it would be unfair for these utilities to retrospectively collect or refund customer monies without an appropriate mechanism for doing so or without adequate notice to ratepayers. However, while each utility's situation may be unique, some balance must be factored in to ensure consistency and fair treatment amongst all utilities. In terms of specific mechanism, the Panel considers that the benefits of establishing interim rates for all other utilities that use a Benchmark Utility to set their capital structure, along with equity return, outweigh other mechanisms.

The Panel directs that interim rates, effective January 1, 2024, be established on a refundable or recoverable basis for all other utilities, except FBC, that currently use the Benchmark Utility to set each utility's capital structure and equity return, pending the BCUC's final decision on Stage 2 of the GCOC proceeding. The Panel confirms Stage 2 of the GCOC proceeding will commence 60 days after the date of this decision.

1.0 INTRODUCTION

1.1 Background

The British Columbia Utilities Commission (BCUC), pursuant to section 59(5)(b) of the *Utilities Commission Act* (UCA) is responsible for ensuring that shareholders of the utilities it regulates are afforded a reasonable opportunity to earn a fair return on their invested capital.

On October 11, 2012, the BCUC established that FortisBC Energy Inc. (FEI) would serve as the benchmark (Benchmark Utility) for any other utility in British Columbia (BC) that uses a Benchmark Utility to set rates.[2] FEI's common equity component was set at 38.5 percent and its return on equity (ROE) was set at 8.75 percent, effective January 1, 2013.[3] On March 25, 2014, the BCUC set the common equity component or equity ratio of the capital structure and equity risk premium over the Benchmark Utility for other regulated utilities in the province.[4] FortisBC Inc. (FBC) was one of the regulated utilities and a full review of its capital structure and equity risk premium was undertaken as part of that proceeding.[5] The BCUC determined that an equity ratio of 40 percent and an equity risk premium of 40 basis points (bps)[6] over the Benchmark Utility for FBC was appropriate.[7] Subsequently, on August 10, 2016, the BCUC reaffirmed FEI's cost of capital.[8] The BCUC also suspended use of the automatic adjustment mechanism formula previously approved in 2013.

By letter dated January 18, 2021, the BCUC noted that significant time had passed since the BCUC's 2013 and 2016 cost of capital reviews and over that period, changes have occurred in financial markets, and pursuant to section 82 of the UCA, issued a Notice of Initiating a Generic Cost of Capital (GCOC) Proceeding.

1.2 Purpose and Scope of the Generic Cost of Capital Proceeding

<u>Purpose of the Proceeding</u>

The purpose of the GCOC proceeding is to establish a method to determine the appropriate cost of capital for regulated utilities in BC[9], as well as to review the appropriateness of continuing the use of a Benchmark Utility, and if so, the appropriate cost of capital for the benchmark.

[2] BCUC 2013 GCOC, Order G-148-12 with Reasons for Decision dated October 11, 2012, Directive 1.
[3] BCUC 2013 GCOC Stage 1, Order G-75-13 and Decision dated May 10, 2013, Directives 1 and 2.
[4] BCUC 2013 GCOC Stage 2, Order G-47-14 and Decision dated March 25, 2014 (2014 Decision), Directives 1 to 6.
[5] 2014 Decision, pp. 4, 60–87.
[6] 1 basis point = 0.01 percent.
[7] 2014 Decision, p. 86.
[8] FEI Application for its Common Equity Component and Return on Equity for 2016 (FEI 2016 COC), Order G-129-16 and Decision dated August 10, 2016 (2016 Decision), Directives 1 and 2.
[9] Order G-156-21 with Reasons for Decision.

Two-Stage Proceeding

By Order G-156-21, the BCUC determined that a two-stage proceeding to establish public utilities' cost of capital was appropriate for the GCOC proceeding, where Stage 1 sets the benchmark ROE (Benchmark ROE) based on a Benchmark Utility, and Stage 2 uses a generic methodology for each utility to determine its unique cost of capital in reference to the Benchmark Utility.[10] Hereafter, Stage 1 refers to the first stage of the GCOC proceeding and Stage 2 refers to the second stage of the same proceeding.

By Order G-205-21, the BCUC determined that the review of deferral account financing costs, as well as any other matters that may arise out of Stage 1 and Stage 2 should be within the scope of the GCOC proceeding, after the completion of Stage 2.[11]

By Order G-281-21, the BCUC found that it was appropriate and efficient to first determine the cost of capital for FEI and FBC, collectively FortisBC, as both utilities are the largest investor-owned natural gas and electric utilities, respectively, in BC.[12] Pursuant to Order G-281-21, and as amended by Order G-288-21, FortisBC filed its evidence for FEI and FBC.[13] By Order G-106-22, the BCUC confirmed that the decision on FEI and FBC's capital structure and ROE will be determined first in Stage 1, and then the BCUC would move onto reviewing which, if any, of the utilities will be the Benchmark Utility in Stage 2.[14]

Order G-106-22 also sets out the scope of Stage 1 as follows:[15]

1. The determination of the allowed ROE and deemed capital structure of FEI and FBC, and the effective dates for which FEI and FBC's cost of capital will take effect.
2. Whether re-establishment of a formulaic ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is warranted, then:
    a) The specifications of the ROE AAM formula.
    b) The frequency that the ROE AAM will apply (i.e. annually or some other frequency) and to whom the ROE AAM will apply.
    c) The date for which the ROE AAM will take effect.
3. The criteria, off-ramps, or other triggers to warrant a future cost of capital proceeding.
4. Any other items that may arise during the proceeding to be considered in Stage 1.

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[10] Order G-156-21 with Reasons for Decision dated May 21, 2021
[11] Order G-205-21 with Reasons for Decision dated July 7, 2021
[12] Order G-281-21 with Reasons for Decision dated September 24, 2021, p.6. , Order G-156-21 with Reasons for Decision dated May 21, 2021, Appendix A, p. 7
[13] Exhibit B1-8, p. 1.
[14] Order G-106-22 dated April 21, 2022.
[15] Ibid.

FortisBC Proposal

In its evidence dated January 31, 2022, FortisBC proposes the following deemed capital structure and ROEs for FEI and FBC, respectively: [16]

- For FEI, a common equity ratio of 45 percent with an ROE of 10.1 percent representing an increase from FEI's current common equity ratio of 38.5 percent and ROE of 8.75 percent; and
- For FBC, a common equity ratio of 40 percent with an ROE of 10.0 percent representing an increase from FBC's current ROE of 9.15 percent, with no change to its common equity ratio.

1.3 Regulatory Process

Stage 1 included a BCUC public hearing process involving the participation of experts in the cost of capital field and several participants, including regulated utilities and interveners.

Experts

Two experts figured prominently in Stage 1: FEI and FBC jointly engaged Mr. James Coyne (Mr. Coyne) of Concentric Energy Advisors Inc. (Concentric) as each utility's expert consultant. The BCUC engaged Dr. Jonathan A. Lesser (Dr. Lesser) of Continental Economics, Inc. (Continental Economics) as an independent expert.

Dr. Lesser's involvement in Stage 1 includes submissions of consultant reports, responses to information requests (IRs) and participation in the oral hearing. Dr. Lesser opined on Mr. Coyne's expert analysis. Dr. Lesser did not perform his own independent calculations and did not present capital structure and ROE recommendations. No intervener engaged an expert to provide expert evidence on FortisBC's cost of capital.[17]

Application Review Process

In accordance with the regulatory timetable established by the BCUC, the BCUC undertook a comprehensive public review process, including the following:

- BCUC Consultant, Dr. Lesser's of Continental Economics consultant report (filed as Exhibit A2-3): "Continental Economics, Inc. Dr. Jonathan A. Lesser Regulated Utility Cost of Capital: Theory and Canadian Practice Report dated August 4, 2021." (Dr. Lesser's Report)[18]
- One round of utilities and interveners' IRs on the BCUC consultant, Dr. Lesser 's Report
- Filing of evidence by FBC and FEI, including evidence of Mr. Coyne (Mr. Coyne Evidence)[19] of Concentric (FortisBC's Evidence)
- Two rounds of IRs on FortisBC's Evidence

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[16] Exhibit B1-8, p. 1.

[17] Corix Multi-Utility Service Inc., Pacific Northern Gas Ltd and Pacific Northern Gas (N.E.) submitted a Brattle Report on the use of a benchmark utility (Exhibits B6-4 and B9-5).

[18] Exhibit A2-3, Continental Economics Inc., "Regulated Utility Cost of Capital: Theory and Canadian Practice" by Dr. Lesser dated August 4, 2021.

[19] Exhibit B1-8, Appendix C, Evidence of Mr. James Coyne, Concentric Energy Advisors Inc., Regarding the Cost of Capital Estimation.

- IR No. 2 to Dr. Lesser regarding Mr. Coyne's Evidence
- Filing of FortisBC's Rebuttal Evidence
- One round of IRs on FortisBC's Rebuttal Evidence
- Update to Mr. Coyne's Model
- Two procedural conferences held on April 14, 2022 and July 8, 2022
- Oral hearing held from November 7, 2022 to November 9, 2022
- Undertakings to the oral hearing
- FortisBC's Final Argument filed by December 23, 2022
- Final arguments from interveners filed by January 27, 2023
- FEI's Reply Argument filed by February 21, 2023

After the filing of arguments, on May 8, 2023, the BCUC invited parties to make submissions on the effective date for all other utilities that use the Benchmark Utility to set their capital structure and equity return.[20] Written submissions from parties were received by May 31, 2023 and replies were received by June 14, 2023.

Registered Utilities and Interveners

Public utilities regulated by the BCUC were categorized as either *Affected Utilities* or *Other Utilities*. The Affected Utilities were designated given each utility's active participation in previous cost of capital proceedings that set a benchmark ROE or the anticipated interest of each utility in the GCOC proceeding as investor-owned utilities. These Affected Utilities were expected to take a lead role in filing evidence for cost of capital matters that may impact them. Other Utilities were also expected to participate as applicants in the GCOC proceeding.

The following Affected Utilities participated in the GCOC proceeding:

- FEI
- FBC
- Corix Multi Utility Services Inc. (Corix)
- Pacific Northern Gas Ltd. (PNG)

The following Other Utilities participated in the GCOC proceeding:

- FortisBC Alternative Energy Service Inc. (FAES)
- Nelson Hydro
- Kyuquot Power Ltd. (KPL)

[20] Exhibit A-31.

- Creative Energy Vancouver Platforms Inc. (Creative Energy)
- River District Energy (RDE)

The following parties registered as interveners:

- Residential Consumer Intervener Association (RCIA)
- Movement of United Professionals (MoveUP)
- Clean Energy Association of BC (CEABC)
- Association of Major Power Customers of BC (AMPC)
- Industrial Customers Group (ICG)
- Commercial Energy Consumers Association of British Columbia (the CEC)
- British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO)
- British Columbia Hydro and Power Authority (BC Hydro)
- Boralex Ocean Falls Limited Partnership (Boralex)

2.0 KEY PRINCIPLES AND DECISION FRAMEWORK

Fair Return Standard

The purpose of Stage 1 is to set a fair return for FEI and FBC. When determining the utilities' cost of capital, the Panel is guided by certain fundamental regulatory principles, including the Fair Return Standard, where the BCUC has a duty to approve rates that will provide the utilities' shareholders a reasonable opportunity to earn a fair return on their invested capital.[21] The Supreme Court of Canada established the principles surrounding the concept of "fair return" for a regulated company in *Northwestern Utilities Limited v. City of Edmonton*[22]:

> 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, as discussed in the National Energy Board's Decision,[23] is fundamental to cost of equity proceedings and requires three elements to be met for a fair and reasonable return on capital:

[21] BCUC 2013 GCOC Stage 1, Order G-75-13 and Decision dated May 10, 2013 (2013 Decision), p. 12.
[22] [1929] S.C.R. 186.
[23] TransCanada PipeLines Limited, RH-2-2004 at p. 17.

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 standards must be met, and none ranks higher in priority to the others.

Standalone Principle

In the BCUC's application of the Fair Return Standard, the utility must also be assessed based on the standalone principle.[24] Mr. Coyne explains that the standalone principle 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.[25] The BCUC had noted the relevance of the standalone principle in past cost of capital decisions and we continue to adhere to this principle to assess FEI and FBC's cost of capital in this proceeding.

Relevance of Past BCUC Decisions

While past BCUC decisions are informative and provide historical context, they are not determinative in this GCOC Stage 1 Decision. We must evaluate the evidence presented in the current proceeding. The use of comparable proxy peers and financial models play a large part of this proceeding, where that evidence was explored extensively by the two cost of capital experts, the BCUC and interveners. FEI and FBC's respective business risks and credit rating information were also similarly tested as part of this proceeding.

Informed judgment, with the support of quantitative and qualitative evidence made available to us during the proceeding, plays a significant role in determining the appropriate cost of capital for each of the two utilities. Therefore, by necessity, certain aspects of our decision are as much art as science.

Decision Framework

We structure the remainder of our decision as follows:

- Section 3.0 provides an overview of the peer data and the timeframe to use that are relevant to our ROE determinations with proxy group data guiding our capital structure determinations.
- Section 4.0 discusses the business risk changes for FEI and FBC from the shareholders' perspective since the BCUC's last assessment of this issue, and the impact this may have on the utilities' overall capital structure.

[24] 2013 Decision, pp. 96, 100.
[25] Exhibit B1-8-1, Appendix C, p. 11.

- Section 5.0 reviews financial modelling analyses presented by Mr. Coyne and the expert evidence of Dr. Lesser.
- Section 6.0 summarizes all the relevant evidence and the Panel's various findings to arrive at a final determination on FEI and FBC's capital structure and ROE and applies a reasonableness check on same.
- Section 7.0 establishes the effective date of our determinations and the timing of Stage 2. Section 8.0 addresses other issues raised during this proceeding.

2.1 Legislative Requirement

The BCUC, pursuant to section 59 of the UCA, is responsible for establishing rates that are not unjust, unreasonable, unduly discriminatory or unduly preferential:

> 59 (1)A public utility must not make, demand or receive
>
> (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or
>
> (b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

Pursuant to section 59 (5), a rate is "unjust" or "unreasonable" if the rate is:

> (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
>
> (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
>
> (c) unjust and unreasonable for any other reason.

In discharging its duty under section 59 of the UCA, the BCUC must at the same time give effect to the regulatory compact by ensuring that shareholders of the regulated utilities are afforded a reasonable opportunity to earn a fair return on their invested capital, otherwise commonly referred to as cost of capital.

2.2 Approach to the Cost of Capital Determination

When determining the cost of capital and the allowable return, there are four key elements that the Panel considers:

1. The actual returns of a proxy group of peer utilities.
2. The business risks facing FEI and FBC, including how those risks may have changed since the last time the BCUC approved a cost of capital for those companies.
3. The credit ratings of FEI and FBC.
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.

Not one of the above elements is, in itself, determinative. Rather, the Panel considers all of these elements together, applying an appropriate weight to each of them as it determines the allowed cost of capital.

The Panel also makes determinations on "adders" to the ROE applied for by FortisBC to account for flotation costs incurred by the parent company and for the need for "financial flexibility", again based on consideration of the above elements.

3.0 CONSIDERATION OF PEER DATA SET

To provide appropriate comparators for the allowed ROE and capital structure for FEI and FBC, our first task is to determine a group of peer companies with ROE data that is readily available. Therefore, we look to publicly traded companies that have business and financial characteristics comparable to those of FEI and FBC to serve as a "proxy" for purposes of the ROE estimation process.

The following sections examine the possible alternatives presented in this proceeding: a Canadian proxy group, a US proxy group, and a North American proxy group. It also discusses the timing of the data sets on which to base the determination of the ROE.

3.1 Consideration of US Data

Mr. Coyne submits that several Canadian regulators, including the BCUC, have recognized the integrated nature of Canadian and US financial markets, that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly traded utilities. As a result, Canadian regulators have adopted a pragmatic view of the use of US data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. Mr. Coyne notes that in its last GCOC decision, the BCUC affirmed the reasonableness of using US market data and proxy groups.[26]

3.2 Proxy Group Selection

Both Mr. Coyne and Dr. Lesser agree with the need to establish a proxy group of companies for the Panel to consider when it determines an appropriate ROE for FEI and FBC. While Mr. Coyne and Dr. Lesser's respective approaches may have differed on the criteria used to select the firms in the proxy group, ultimately, Dr. Lesser "withdrew" his evidence on proxy groups during cross-examination and supported using Mr. Coyne's proxy groups.[27]

Mr. Coyne developed five proxy groups for his ROE analysis (see Table 1). He notes that the selected companies possess a set of business and financial attributes that are similar to FEI and FBC's regulated gas and electric utility operations, thus providing a reasonable basis for ROE and capital structure estimates.

The Canadian proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Due to their limited number, the only screening criterion was an investment grade credit rating, which all companies in the utility sector possess. In contrast, to create a group of essentially pure-play US gas

[26] Exhibit B1-8-1, Appendix C, pp. 37–38.
[27] Transcript Volume 4, p. 421.

and electric utilities with similar risk profiles to FEI and FBC respectively, Mr. Coyne applied the screening criteria discussed below.

He explains that the utilities must:[28]

- Have credit ratings of at least BBB+ from Standard &Poor's Global Ratings (S&P) or Baa1 from Moody's Investors Service (Moody's);
- Consistently pay quarterly cash dividends;
- Have positive earnings growth rate projections from at least two sources;
- Derive at least 65 percent (gas proxy) or 70 percent (electric proxy) of operating income from regulated operations in the period from 2018 to 2020;
- Derive at least 90 percent of regulated operating income from natural gas distribution (gas proxy) or electric (electric proxy) utility service in the period from 2018 to 2020; and
- Not have been involved in a merger or other significant transformative transaction during the evaluation period.

Table 1: Proxy Groups Companies[29]

Company	Canadian Utilities	U.S. Gas Utilities	U.S. Electric Utilities	N.A. Gas Utilities	N.A. Electric Utilities
Algonquin Power and Utilities Corp.	✓				✓
AltaGas Ltd.	✓			✓	
Canadian Utilities Limited	✓			✓	✓
Emera Inc.	✓				✓
Enbridge, Inc.	✓			✓	
Hydro One, Ltd.	✓				✓
New Jersey Resources Corporation		✓		✓	
Northwest Natural Gas Company		✓		✓	
ONE Gas, Inc.		✓		✓	
Spire, Inc.		✓		✓	
Alliant Energy Corp.			✓		✓
American Electric Power Company			✓		✓
Duke Energy Corporation			✓		✓
Entergy Corporation			✓		✓
Exelon Corp			✓		✓
Evergy Inc.			✓		✓
NextEra Energy Inc.			✓		✓
OGE Energy Corporation			✓		✓
Pinnacle West Capital Corp.			✓		✓
Portland General Electric Company			✓		✓

[28] Exhibit B1-8-1, Appendix C, pp. 37, 39–42.

[29] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Figures 18-22, pp. 40–43.

As shown in Table 1, there is only one Canadian proxy group, comprised of six companies that are a combination of both gas and electric companies. For the US proxy groups, four US gas distribution utility companies and 10 US electric companies met the respective screening criteria. Mr. Coyne then created North American proxy groups by combining the Canadian and US regulated utilities. On the gas side, he chose the three Canadian regulated utilities that have significant natural gas operations, plus the US gas proxy companies. For the electric side, he selected the four Canadian regulated utilities that are primarily electric companies, plus the US electric proxy companies.[30]

Table 2 and Table 3 compare FEI and FBC with the Canadian and US proxy companies on key metrics such as size (as measured by market capitalization), revenues, assets, and the share of regulated income.

Table 2: Canadian and US Gas Utilities[31]

Canadian Utilities	**Market Cap (Can$ million) as of 12/31/21**	**Total revenue (Can$ million) as of 12/31/20**	**Total assets (Can$ million) as of 12/31/20**	**Regulated income/total income (%)[32]**
FEI	n.a.	1,385[33]	7,738[34]	100%[35]
AltaGas Ltd.	7,651	5,587	21,532	140%
Canadian Utilities Limited[36]	9,878	3,233	20,296	64%
Enbridge Inc.	100,103	39,087	160,276	16%
U.S. Utilities	**US$ million**	**US$ million**	**US$ million**	**Regulated gas income/total reg income (%)**
New Jersey Resources Corporation	3,940	1,954	5,570	101%
Northwest Natural Gas Company	1,495	759	3,599	91%
ONE Gas, Inc.	4,158	1,530	6,029	100%
Spire, Inc.	3,375	1,855	8,241	100%

[30] Exhibit B1-8-1, Appendix C, pp. 41–42.

[31] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Exhibit JMC-FEI-3, pp. 1–2.

[32] Source: Company 10-K reports, average of three most recent years.

[33] Exhibit B1-8-1, Appendix C, Figure 47, p. 107.

[34] Ibid., Appendix D, pdf p. 472.

[35] Ibid., Appendix C, p. 112.

[36] Canadian Utilities Limited is a combination electric and gas utility. Earnings are 53.3% electric and 46.7% gas; Assets are 56.4% electric and 43.6% gas; and revenues are 47.1% electric and 52.9% gas.

Table 3: Canadian and US Electric Utilities[37]

Canadian Utilities	Market Cap (Can$ million) as of 12/31/21	Total revenue (Can$ million) as of 12/31/20	Total assets (Can$ million) as of 12/31/20	Regulated income/total income (%)
FBC	n.a.	412[38]	2,437[39]	100%[40]
Algonquin Power and Utilities Corp.	12,276	2,249	16,850	86%
Canadian Utilities Limited	9,878	3,233	20,296	64%
Emera Inc.	16,432	5,506	31,234	92%
Hydro One, Ltd.	19,687	7,290	30,294	100%
U.S. Utilities	**US$ million**	**US$ million**	**US$ million**	**Reg. electric income/total reg income (%)**
Alliant Energy Corp.	15,390	3,416	17,710	91%
American Electric Power Company	44,810	14,919	80,757	100%
Duke Energy Corporation	80,668	23,453	162,388	91%
Entergy Corporation	22,641	10,114	58,239	99%
Exelon Corp	56,418	33,039	129,317	91%
Evergy Inc.	15,574	4,913	27,115	100%
NextEra Energy Inc.	183,185	17,997	127,684	100%
OGE Energy Corporation	7,683	2,122	10,719	100%
Pinnacle West Capital Corp.	7,964	3,587	20,020	100%
Portland General Electric Company	4,732	2,145	9,069	100%

In Mr. Coyne's view, the US gas and electric proxy groups are more comparable to FEI and FBC, respectively, in terms of business risk than the Canadian proxy group utilities, many of which have significant non-gas or non-electric operations and unregulated operations.[41] In response to Dr. Lesser's critique that the Canadian proxy group includes both gas and electric utilities and consequently is neither comparable to FEI or FBC,[42] Mr. Coyne explained that he presented a Canadian proxy group to address any concerns that may arise regarding the comparability of US proxy groups in establishing the allowed ROE for FEI and FBC.[43] Mr. Coyne submits that his US proxy groups address concerns regarding the comparability of these companies to FEI and FBC respectively, from an investment perspective because:[44]

1) The US gas proxy group is comprised of companies that derive 91 percent of each company's net operating income from regulated activities, 99 percent of operating income and 98 percent of revenues from gas utility operations, and dedicate 97 percent of assets to regulated gas utility service; and

[37] Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Exhibit JMC-FBC-3, pp. 1–2.
[38] Exhibit B1-8-1, Appendix C, Figure 57, p. 133.
[39] Ibid., Appendix D, pdf p. 576.
[40] Ibid., Appendix C, p. 138.
[41] Exhibit B1-8-1, Appendix C, p. 55.
[42] Exhibit A2-20, BCUC IR 1.3.
[43] Exhibit B1-21, Part 2, p. 9.
[44] Exhibit B1-8-1, Appendix C, p. 55.

2) The US electric proxy group is comprised of companies that derive 95 percent of each company's net operating income from regulated activities, 97 percent of both operating income and revenues from electric utility operations and dedicate almost 97 percent of assets to regulated electric utility service.

In response to an IR asking Dr. Lesser what weight he would place on the Canadian versus US proxy groups, he stated that a better statistical approach would be to combine the Canadian and US companies into a joint North American proxy group for gas and electric utilities, respectively.

Dr. Lesser explained that this approach is reasonable because the countries' economies are highly integrated and capital markets are international. Dr. Lesser also suggested that one could evaluate differences between the allowed ROE values calculated for the Canadian and US companies. As an example, Dr. Lesser explained that if the four Canadian electric companies all had much lower allowed ROEs than the US companies, the BCUC could take that into consideration when setting the ROE for FEI and FBC.[45]

At the oral hearing, Mr. Coyne noted his agreement with Dr. Lesser's recommendation to use a North American proxy group for electric and gas utilities. Mr. Coyne also noted, one would have to "accept a little bit less Canadian representation" in forming a North American proxy group and explained that it is challenging to find a Canadian company that would pass the same screening criteria that he applied to the US companies.
With respect to a North American gas proxy group, Mr. Coyne believes that, of the Canadian companies, only AltaGas Ltd. would pass the screening criteria. (Enbridge Inc. would not pass due its low proportion of earnings from natural gas operations and similarly, Canadian Utilities Limited would not pass due to an approximate equal focus on electric and gas operations). With respect to a North American electric proxy group, Mr. Coyne expects three to four Canadian companies would pass the screening criteria. [46]

FortisBC acknowledges that Mr. Coyne developed his initial recommendation based on the results of his US proxy groups, consistent with the BCUC's 2016 Decision.[47] However, the evidence in this proceeding suggests that it would be appropriate for the BCUC to give primary weight to results based on Mr. Coyne's North American gas and electric proxy groups, in line with both experts' evidence, who agree that the extent of economic and market integration in North America justifies the use of North America-wide proxy groups to estimate the authorized ROE for FEI and FBC.[48]

Based on Mr. Coyne's explanation, FortisBC states that since only one Canadian gas company and three Canadian electric companies pass his screening criteria, there are substantial similarities in the composition of the US proxy groups and the North American proxy groups.[49] FortisBC also notes that Mr. Coyne testified that he has been advocating for using a North American proxy group approach for many years and would embrace a decision by the BCUC to adopt this approach in this proceeding.

FortisBC states that Dr. Lesser is in full agreement with Mr. Coyne on the extent of integration of the North American economy and capital markets and had advocated for the use of integrated North American gas and

[45] Exhibit A2-20, BCUC IR 1.3.
[46] Transcript Volume 3, p. 336 Line 21 to p. 338 Line 8.
[47] FBC Application for its Common Equity Component and Return on Equity for 2016 [FEI 2016 Cost of capital (COC)], Order G-129-16 and Decision dated August 10, 2016 (2016 Decision).
[48] FortisBC Final Argument, pp. 139–140.
[49] Ibid., pp. 140–141.

electric proxy groups. Dr. Lesser explains that "*per se* geographical constraints on the location of proxy group companies may eliminate comparable firms." Dr. Lesser observes that the Federal Energy Regulatory Commission (FERC) now allows for Canadian companies to be included in proxy groups for setting ROEs for pipelines and transmission utilities, given the level of integration and the similarity in how they are regulated.[50]

Positions of Parties

ICG

ICG does not challenge the proxy group companies of Concentric.[51] ICG agrees with FEI and FBC's submissions that the BCUC should place the greatest weight on the North American proxy groups.[52]

BCOAPO

Given the agreement of both Dr. Lesser and Mr. Coyne that the preferred approach is to use the North American proxy groups for gas and electric utilities, BCOAPO agrees with FortisBC's submission that "the BCUC should place the greatest weight on the North American proxy group results in light of the expert evidence." However, BCOAPO points to statements by Mr. Coyne and FortisBC, where both parties indicated that only three out of four Canadian electric utilities and only one out of three Canadian gas utilities would pass the screening criteria to be included in the appropriate North American proxy groups. Therefore, BCOAPO submits that the results for the North American proxy groups will need to be revised.[53]

As part of its final argument, BCOAPO has recalculated the ROE from the Multi-Stage DCF model and CAPM for: 1) a revised North American gas utility proxy group by removing Enbridge Inc. and Canadian Utilities Limited, leaving just AltaGas Ltd. as a Canadian gas utility in the new North American gas proxy group and 2) a revised North American electric utility proxy group by removing only Canadian Utilities Limited and leaving Algonquin Power and Utilities Corp., Emera Inc., and Hydro One Ltd. as the three Canadian electric utilities in the new North American electric proxy group.[54]

The CEC

The CEC submits that the experts' agreement on the proxy groups and on the North American integration of the two economies and capital markets is useful to the BCUC. However, the CEC does not agree that the integration leads automatically to the exclusion of US proxy group data and results by replacement with a North American proxy group. There are significant differences in the data which the CEC submits should be considered and given substantial weighting.[55] Thus, the CEC recommends that the BCUC give substantial weighting to the Canadian utilities, US utilities, and North American utilities proxy groups, and then average the results of each of these proxy groups.[56]

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[50] FortisBC Final Argument, pp. 142–143.
[51] ICG Final Argument, p. 8.
[52] Ibid., p. 10.
[53] BCOAPO Final Argument, pp. 11–12.
[54] Ibid., pp. 43–44.
[55] The CEC Final Argument, p. 39.
[56] Ibid., p. 42.

RCIA

RCIA opposes the inclusion of US market data in ROE calculations for two reasons. First, RCIA submits that "the Canadian MRP should only be measured against the Canadian proxy group, as being country (and market) specific." And second, if the BCUC were to accept US data, there is no evidence to support an equal weighting of Canadian and US data in ascertaining an appropriate Canadian ROE.[57]

FortisBC Reply Argument

FortisBC points out that ICG has used internally inconsistent reasoning to reach its low recommended ROE. On the one hand, ICG agrees with the experts that the BCUC should give the greatest weight to the North American proxy group when determining ROE. FortisBC surmises that ICG's position is no doubt influenced by the fact that this tends to reduce FBC's ROE significantly relative to using the Canadian proxy group. On the other hand, ICG advocates for only using the Canadian utilities when determining the common equity ratio, while giving no weight to the same US proxy companies that ICG advocates using for the ROE calculations included in the North American proxy group.[58]

FortisBC submits that BCOAPO's exclusions of two companies from the North American gas and/or electric proxy groups are unwarranted. Even though Mr. Coyne has stated that he would probably have had to exclude Enbridge Inc. and Canadian Utilities Limited from his North American proxy groups if his screens were rigidly applied to Canadian companies, FortisBC points out that he refrained from doing so, as it would have undermined the value of using a North American proxy group with too few comparable Canadian utility companies. As noted by Dr. Lesser, there is a trade-off between larger proxy groups providing more statistically valid results, while some firms become less "comparable" to the regulated firm under review. In conclusion, FortisBC submits that Enbridge Inc. and Canadian Utilities Limited should remain a part of the North American proxy groups.[59]

FortisBC submits that the CEC's suggestion to average results from all proxy groups is unnecessary. Citing the experts' agreement on the appropriateness of using North American proxy groups, FortisBC submits that this approach is more appropriate than averaging the results of the Canadian, US and North American proxy groups. FortisBC points to the experts' agreement on Mr. Coyne's screening criteria for the North American and US proxy groups, while both experts noted the limited size and composition of the Canadian proxy group.[60]

FortisBC submits that RCIA's opposition to US data is inconsistent with the consensus expert evidence and regulatory practice. FortisBC notes that RCIA stands as the only intervener not to acknowledge the need to rely on US data. FortisBC submits that RCIA's position that Mr. Coyne has used assumptions that "baselessly incorporate … non-Canadian data, which in turn raise the assumption values and subsequently the recommended ROEs" is without merit. Indeed, using the October 2022 data, FortisBC points out that relying on the Canadian proxy group tends to slightly increase the overall ROE.[61]

[57] RCIA Final Argument, p. 17.
[58] FortisBC Reply Argument, pp. 55–56.
[59] FortisBC Reply Argument, pp. 57–58.
[60] Ibid., p. 57.
[61] Ibid., p. 58.

FortisBC also submits that there is ample basis for using US data in ROE analysis: a) both experts agree it is appropriate and both favour North American proxy groups; b) the BCUC's 2016 Decision used the US proxy groups results, citing both increasing integration and the scarcity of Canadian publicly traded utilities; c) other Canadian regulators have taken a similar approach; and d) the extent of integration has only increased over time.[62]

Finally, FortisBC observes that RCIA has chosen to rely on US data to estimate the risk-free rate when this has the effect of suppressing its ROE results.[63]

Panel Determination

We begin our analysis by noting that both Mr. Coyne and Dr. Lesser agree with the need to establish a proxy group of companies. In doing so, we are cognizant of the need to ensure that we are indeed comparing apples to apples, notwithstanding any jurisdictional and operational differences between the utility in question and its proposed peers**.**

Furthermore, the makeup of any proxy group inherently involves some degree of professional judgment and discretion. Unfortunately, there are no reasonable comparators to FEI and FBC in BC. This is because FEI is the single largest natural gas distributor in the Province (PNG is considerably smaller), and in respect of FBC, there are no other vertically integrated electric utilities that are of comparable size within BC. This requires us to look elsewhere in Canada for suitable proxies to FEI and FBC.

In an ideal world, there would be sufficient comparators to each of FEI and FBC in Canada to allow the BCUC to use only data pertaining to Canadian counterparts as a starting point. However, the reality is to the contrary. As Mr. Coyne notes in his evidence, using a Canadian proxy group comprised of publicly traded, regulated Canadian electric and natural gas utility companies with comparable business and financial characteristics yields only six utilities (three electric and three gas). Due to this limited number, the only screening criterion that Mr. Coyne uses is an investment grade credit rating, which all six utilities possess. However, as Table 2 above shows, all three Canadian gas utilities (AltaGas Ltd., Canadian Utilities Limited and Enbridge Inc.) have total assets and annual revenues that range from double to 28x those of FEI, and one of them (Enbridge Inc.) only derives 16 percent of its total income from its regulated activities.

With respect to the three Canadian electric utilities, Table 3 shows that all three have total assets and annual revenues that range from 5x to 17x those of FBC. This suggests that these comparators may provide limited value for the purpose of determining an appropriate ROE for FEI and FBC and that our review of proxy groups therefore should not be confined to Canadian utilities alone.

With respect to using non-Canadian comparators, as Mr. Coyne correctly points out, several Canadian regulators, including the BCUC, have recognized the integrated nature of Canadian and US financial markets, that Canadian utilities are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly traded utilities. This has led to Canadian regulators adopting a pragmatic view of the use of US data and proxy groups to estimate the allowed ROE for Canadian regulated utilities. We see no

[62] FortisBC Reply Argument, p. 58.
[63] Ibid., p. 59.

reason to deviate from the BCUC's previous determination regarding the reasonableness of using US market data and proxy groups and endorse the wisdom of continuing to do so in light of the small sample size of Canadian comparators notwithstanding any jurisdictional differences. We accept Mr. Coyne's evidence that the US gas and electric proxy groups are more comparable to FEI and FBC, respectively, in terms of business risk than the Canadian proxy group utilities, many of which have significant non-gas or non-electric operations and unregulated operations.

We agree as a matter of principle with the experts' suggestion to give primary weight to North American gas and electricity proxy groups. As Dr. Lesser notes, this change in practice is reflected in FERC now allowing for Canadian companies to be included in proxy groups for setting ROEs for US pipelines and transmission utilities because of the level of integration and the similarity in how they are regulated.[64]

We note that ICG and BCOAPO both agree with FortisBC's submission that "the BCUC should place the greatest weight on the North American proxy group results in light of the expert evidence." We reject the CEC's suggestion to give substantial and equal weighting to the Canadian utilities, US utilities, and North American utilities proxy groups, and to simply average the results of each of these proxy groups. For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.

However, with respect to the use of a North American gas proxy group, Mr. Coyne believes that only AltaGas Ltd. from the Canadian utilities would pass the six screening criteria he uses to create a group of essentially pure-play US gas and electric utilities with similar risk profiles to FEI and FBC respectively (Enbridge Inc. would not pass due its low portion of earnings from natural gas operations and similarly, Canadian Utilities Limited would not pass due to an approximate equal focus on electric and gas operations). With respect to a North American electric proxy group, Mr. Coyne expects three to four Canadian companies would pass the screening criteria. As a result, we find merit in BCOAPO's submission that Mr. Coyne's North American proxy groups will need to be revised to exclude the non-qualifying Canadian utilities.

Finally, we reject RCIA's submission for the BCUC to only use Canadian data for the Canadian proxy group because it is country and market specific. Instead, we agree with FortisBC that there is ample basis to include US data in our ROE analysis because:

- There are insufficient comparators to each of FEI and FBC in Canada to allow the BCUC to use only data pertaining to Canadian counterparts;
- Both experts agree that the inclusion of US data is appropriate and both favour the use of North American proxy groups;
- The BCUC's 2016 Decision used US proxy groups results, citing both increasing integration and the scarcity of Canadian publicly traded utilities; and

[64] Exhibit A2-3, Lesser Report, pp. 14–15.

- Other Canadian regulators (and more recently FERC) have taken a similar approach; and the extent of North American financial and capital markets integration has only increased over time.

As for the weighting of the ROE results amongst the North American proxy group as between the Canadian utilities and the US utilities, we find that to be largely a matter of judgment that is within our discretion. However, we accept both Mr. Coyne and BCOAPO's caution about the need to remove the non-qualifying Canadian utilities from the proxy group based on Mr. Coyne's screening criteria and the resulting impact that this would have on our assessment of an appropriate ROE. In Sections 5.2.5 and 5.3.3 of this decision, we review the impact of the removal of the non-qualifying Canadian utilities from the North American proxy group on the resulting ROEs.

3.3 Use of Recent Data – October 2022

More than two years have elapsed since the BCUC initiated this proceeding on January 18, 2021. Mr. Coyne filed his original expert evidence with ROE results that were based on December 2021 data. As Mr. Coyne relied on the average of the CAPM and Multi-Stage DCF model to estimate the allowed ROE for FEI and FBC, he believes, based on the December 2021 data, that a reasonable estimate of FEI's required cost of equity is 10.1 percent and that of FBC is 10.0 percent, based on the US proxy groups. Not surprisingly, due to the passage of time, the Panel is concerned about the staleness of that data as a basis for establishing an ROE in 2023. Therefore, based on FortisBC's submission that both experts had indicated a preference for using the latest data, we directed Mr. Coyne to update his ROE analysis using market data inclusive of September 30, 2022.[65]

3.3.1 Mr. Coyne's Original ROE Results

Mr. Coyne's ROE results based on December 2021 data are shown in Table 4 below for the four models that he presented: CAPM, Constant Growth DCF, Multi-Stage DCF and Risk Premium Model.

Table 4: Summary of Results – December 2021[66, 67]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.68%	10.67%	11.05%	11.12%	10.8%
Constant Growth DCF	11.61%	10.39%	10.99%	9.57%	9.87%
Multi-Stage DCF	10.28%	9.53%	10.05%	8.82%	9.07%
Risk Premium		9.97%	9.97%	10.01%	10.1%
Average	**10.9%**	**10.3%**	**10.7%**	**10.0%**	**10.0%**
Avg CAPM and Multi-Stage DCF	**10.5%**	**10.1%**	**10.6%**	**10.0%**	**9.9%**

Table 4 shows that the average of all four models for the US gas proxy group is 10.3 percent, within the range of 9.53 percent to 10.67 percent, and the four-model average for the US electric proxy group is 10.0 percent,

65 Order G-217-22, Appendix A, p. 11.

66 Information in the table has been compiled from Exhibit B1-8-1, Appendix C, Figures 1 and 2, pp. 4–5.

67 DCF results are based on 90-day average stock prices for proxy group companies. Results include a 50 bps for flotation costs and financial flexibility, except for U.S. risk premium results. The risk premium analysis was only conducted for the U.S. proxy groups; thus, there are no risk premium results the Canadian proxy group. The CAPM results do not include a leverage adjustment using the Hamada formula. The CAPM results do not include an adjustment for FBC's small size.

within the range of 8.82 percent and 11.12 percent. As Mr. Coyne relied on the average of the CAPM and Multi-Stage DCF model to estimate the allowed ROE for FEI and FBC, he opines, based on the December 2021 data, that a reasonable estimate of FEI's required cost of equity is 10.1 percent and that of FBC is 10.0 percent, based on the US proxy groups. As noted earlier, Mr. Coyne views that the US proxy group utilities are more comparable to FEI and FBC, respectively, in terms of business risk than those of the Canadian proxy group.

3.3.2 ROE Results from the September 2022 Update

Based on FortisBC's submission that both experts had indicated a preference for using the latest data, the BCUC directed Mr. Coyne to update his ROE analysis using market data inclusive of September 30, 2022.[68] Mr. Coyne's updated analysis using the September 30, 2022 data lowered the two-model average (Multi-Stage DCF and CAPM) from 10.1 percent (proposed) to 9.3 percent for FEI and from 10.0 percent (proposed) to 9.5 percent for FBC, based on the respective US proxy groups. Mr. Coyne describes those results as counter-intuitive in a macro environment characterized by sustained higher levels of inflation and substantially higher interest rates.[69] In his view, the December 2021 market data represents more normal market circumstances, before the war in Ukraine, aggressive interest rates' increases, sustained elevated levels of inflation, amongst other factors, significantly impacted capital markets in 2022. Accordingly, Mr. Coyne considers the December 2021 results to be more indicative of the actual cost of equity than data ending in September 2022 which are skewed by these market disruptions. Given the highly abnormal nature of 2022 and the transitory market circumstances, he is reluctant to change his ROE recommendations based solely on the September 2022 market data.[70]

The updates are shown below in Table 5.

Table 5: Summary of Results – September 2022 Update[71, 72]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.08%	9.87%	10.24%	10.43%	10.17%
Constant Growth DCF	11.74%	9.69%	10.72%	9.66%	9.92%
Multi-Stage DCF	10.24%	8.81%	9.57%	8.64%	8.93%
Risk Premium		10.12%	10.12%	10.17%	10.17%
Average	**10.7%**	**9.6%**	**10.2%**	**9.7%**	**9.8%**
Avg CAPM and Multi-Stage DCF	**10.2%**	**9.3%**	**9.9%**	**9.5%**	**9.6%**

Mr. Coyne's updated analysis lowered the two-model average (Multi-Stage DCF and CAPM) from 10.1 percent (proposed) to 9.3 percent for FEI and from 10.0 percent (proposed) to 9.5 percent for FBC, based on the respective US proxy groups. Mr. Coyne describes those results as counter-intuitive in a macro environment characterized by sustained higher levels of inflation and substantially higher interest rates.[73] In Mr. Coyne's view, these market circumstances require an examination of the models and inputs used to estimate ROEs and the

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68 Order G-217-22, Appendix A, p. 11.

69 Exhibit B1-8-1-2, pp. 2, 4.

70 Exhibit B1-8-1-2, pp. 6–7.

71 Information in the table has been compiled from Exhibit B1-8-1-2, Figures 1 and 3, pp. 2–3.

72 See footnote 67.

73 Exhibit B1-8-1-2, pp. 2, 4.

application of informed judgment. With respect to the CAPM, Mr. Coyne expresses the following concern related to the estimation of government bond yields (risk-free rate):

> The forecast interest rates used in the September 2022 analysis are well below current levels. This may be due to the Consensus Economics' forecast lagging the fast-moving market, or to an expectation that central bank actions will stall the economy and bring down interest rates in the future. This has a direct impact on the CAPM and Risk Premium models.

With respect to the DCF models, Mr. Coyne expresses the concern that utility stock prices had responded slowly to the down market in 2022 so the 90-day historic stock price averages used in the DCF models are not reflective of the market condition as of the end of September 2022.

Therefore, Mr. Coyne has replaced the forecast bond yields with the current bond yields (spot price) in the CAPM formula to examine the impact of this factor on the output of the CAPM (see Table 6, CAPM results). Also, Mr. Coyne has replaced the 90-trading day average utility stock prices with the current stock prices (spot price). The Multi-Stage DCF model results increase significantly across all proxy groups, and for the most part, surpasses the December 2021 results (see Table 6, Multi-Stage DCF results).

Table 6: Summary of Results – September 2022 Update – Spot Update[74, 75]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	**10.10%**	**10.33%**	**10.51%**	**10.88%**	**10.50%**
Constant Growth DCF	12.38%	10.04%	11.14%	10.17%	10.49%
Multi-Stage DCF	**11.06%**	**9.21%**	**10.07%**	**9.23%**	**9.61%**
Risk Premium		10.22%	10.22%	10.28%	10.28%
Average	11.2%	10.0%	10.6%	10.1%	10.2%
Avg CAPM and Multi-Stage DCF	10.6%	9.8%	10.3%	10.1%	10.1%

Mr. Coyne notes, when incorporating these input changes into the CAPM and DCF model, the model results shift back towards those estimated in December 2021. In his view, the December 2021 market data represents more normal market circumstances, before the War in Ukraine, aggressive interest rates' increases, sustained elevated levels of inflation, amongst other factors, significantly impacted capital markets in 2022. While Mr. Coyne would not rely on spot market data to estimate the CAPM and Multi-Stage DCF model, he considers the spot market results more indicative of the actual cost of equity than data ending in September 2022 skewed by these market disruptions. The highly abnormal nature of 2022 and the transitory market circumstances explain Mr. Coyne's reluctance to change his ROE recommendations based solely on the September 2022 market data.[76]

3.3.3 ROE Results from the October 2022 Update

At the oral hearing, Mr. Coyne offered to further update his ROE model results to the end of October 2022. His updates were based on both the 90-day and 30-day average stock prices for the DCF model and are shown

[74] Information in the table has been compiled from Exhibit B1-8-1-2, Figures 3 and 4, p. 6.
[75] See footnote 67.
[76] Exhibit B1-8-1-2, pp. 6–7.

below, in Table 7 and Table 8, respectively. That analysis shows an increase in ROE[77] from the September 2022 data to an ROE of 9.5 percent (90-day) and 9.8 percent (30-day),) respectively for FEI, and 9.6 percent (90-day) and 10.0 percent (30-day) for FBC, based on the October 2022 data which more closely approximate the results using the December 2021 data.[78]

A more in-depth discussion on the appropriate averaging period to calculate the dividend yield in the Multi-Stage DCF model can be found in Section 5.3.1 below.

Table 7: Summary of Results – October 2022 Update (Scenario A.2, 90-day) [79]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.12%	9.96%	10.30%	10.51%	10.24%
Constant Growth DCF	11.98%	9.81%	10.95%	9.67%	10.09%
Multi-Stage DCF	10.46%	8.94%	9.72%	8.74%	9.11%
Risk Premium		10.12%	10.12%	10.16%	10.16%
Average	**10.9%**	**9.7%**	**10.3%**	**9.8%**	**9.9%**
Avg CAPM and Multi-Stage DCF	**10.3%**	**9.5%**	**10.0%**	**9.6%**	**9.7%**

Table 8: Summary of Results – October 2022 Update (Scenario A.3, 30-day)[80]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
CAPM	10.07%	10.27%	10.46%	10.82%	10.45%
Constant Growth DCF	12.35%	10.07%	11.22%	9.98%	10.44%
Multi-Stage DCF	10.93%	9.24%	10.03%	9.10%	9.52%
Risk Premium		10.12%	10.12%	10.16%	10.16%
Average	**11.1%**	**9.9%**	**10.5%**	**10.0%**	**10.1%**
Avg CAPM and Multi-Stage DCF	**10.5%**	**9.8%**	**10.2%**	**10.0%**	**10.0%**

During the oral hearing, Mr. Coyne discussed the October 2022 data beginning to reflect more normal conditions with alignment around expectations for utility stock prices to decrease and dividend yield to start increasing, "but yet not fully in sync with where bond yields were going."[81]

In its final argument, FortisBC submits that the evidence supports a finding that the required cost of equity for FEI and FBC is, respectively, 10.1 percent (on 45 percent common equity) and 10.0 percent (on 40 percent common equity). FortisBC states that these proposed ROEs are based on the recommendations of Mr. Coyne, who is the only expert in this proceeding who conducted a full cost of capital analysis.[82] FortisBC also notes the

[77] Consisting of the average of CAPM and Multi-Stage DCF ROEs.
[78] Transcript Volume 4, p. 574, Lines 11–12.
[79] Information in the table has been compiled from Exhibit B1-50, Figures 3 and 4, p. 6.
[80] Information in the table has been compiled from Exhibit B1-50, Figures 5 and 6, p. 7.
[81] Transcript Volume 4, p. 574, Lines 11–12.
[82] FortisBC Final Argument, p. 121.

experts' alignment on key aspects of the analysis, including the reasonableness of relying primarily on the most recent October 2022 data.[83]

FortisBC states that, although the BCUC should be giving the most weight to October 2022 data, the BCUC can take additional comfort from the fact that there is reasonable alignment between the December 2021 and October 2022 ROE results. Mr. Coyne regards the December 2021 results as more reflective of "more normal market circumstances" than the September 2022 results filed prior to the oral hearing. The October 2022 results show the markets emerging from extraordinary market conditions over the summer, which have suppressed the September 2022 Update model results.[84]

Positions of Parties

<u>ICG</u>

ICG agrees that the BCUC should adopt the use of the October 2022 data. However, ICG submits that the BCUC should not conclude that the October 2022 results are potentially understating the investor-required return, as this would be inconsistent with the Efficient Market Hypothesis[85] and investor expectations would be substituted with those of the BCUC.[86]

<u>BCOAPO</u>

BCOAPO points to the experts' agreement to use the most recent market data to justify BCOAPO's use of Mr. Coyne's October 2022 results for its own ROE calculations and recommendations.

<u>The CEC</u>

The CEC submits that the BCUC should give weight to Mr. Coyne's ROE calculations using October 2022 data in making its informed judgement about how capital markets are impacting ROE models and what is a fair return, as these results appear to be better and sufficiently recent. The CEC further submits that FortisBC's observation that there is reasonable alignment between results based on the October 2022 data and the December 2021 data is important and helps validate the use of the October 2022 data on which the BCUC should rely.[87]

The CEC notes the sensitivity of ROE modelling to movements in bond yields and prices in stock markets to be out of sync for extended periods of time, and that use of data that may not be in sync could distort the results significantly. The CEC submits that the experts' attention to this and the selection of preferred data points are important factors for the BCUC to be relying on and finding appropriate as the basis for its ROE decisions.[88]

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[83] FortisBC Final Argument, p. 122.
[84] Ibid., p. 146.
[85] Efficient Market Hypothesis is described in Section 4.0.
[86] ICG Final Argument, p. 11.
[87] The CEC Final Argument, p. 38, 43.
[88] Ibid., p. 44.

RCIA

RCIA makes no submission *per se* on which data to use; however, RCIA has relied on the December 2021 data to make its ROE recommendations.

FortisBC Reply Argument

FortisBC states that, while RCIA does not explain why it has disregarded the October 2022 data, its reliance on December 2021 data is a significant determinant of its low ROE recommendations. Even if the BCUC were to accept each of RCIA's methodological changes to Mr. Coyne's CAPM, which FortisBC submits the BCUC should not do, simply updating RCIA's recommended changes with October 2022 data produces an ROE of 9.43 percent, which is significantly higher than RCIA's proposed 8.00 percent to 8.75 percent. And averaging that result with the Canadian Multi-Stage DCF result of 10.46 percent would result in an ROE of 9.94 percent for both FEI and FBC. FortisBC submits that these values support Mr. Coyne's recommendations of 10.1 percent (on 45 percent common equity) for FEI and 10.0 percent (on 40 percent common equity) for FBC.[89]

Panel Discussion

The Panel is persuaded by Mr. Coyne's evidence, as the only expert in the proceeding who has prepared a full cost of capital analysis, that the October 2022 data are beginning to reflect more normal conditions with alignment around expectations for utility stock prices to decrease and dividend yield to start increasing, albeit "yet not fully in sync with where bond yields were going."

The Panel accepts that overall, the October 2022 results show the markets emerging from extraordinary market conditions over the summer of 2022, which may have artificially suppressed Mr. Coyne's September 2022 Update model results due to market volatility.[90]

The Panel is persuaded about the reasonableness of using the October 2022 market data, being the most recent publicly available data, to inform us in the establishment of an appropriate cost of capital. In that regard, we note the two experts' alignment on key aspects of the analysis, including the reasonableness of relying primarily on the most recent October 2022 data.[91] We note that all the interveners who provided submissions on the timing of the data support the use of the October 2022 data.

While both FortisBC and the CEC point to the fact there is reasonable alignment between the results based on the October 2022 data and those based on the December 2021 data as an important factor that helps to validate the use of the October 2022 data,[92] we do not consider that to be persuasive. Rather, we find that the passage of time has rendered the December 2021 data stale as a basis for establishing an appropriate cost of capital in 2023, and that, absent special circumstances, reliance on the most current data provides a more sound and principled basis for setting the cost of capital.

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[89] FortisBC Reply Argument, pp. 50–51.
[90] FortisBC Final Argument, p. 146.
[91] Ibid., p. 122.
[92] The CEC Final Argument, p. 38, 43.

4.0 BUSINESS RISK AND CREDIT RATINGS

FortisBC describes business risk analysis as an important factor in an investor's decision-making process and states, from the investors' perspective, any factor that may negatively impact a utility's current and future cash flows should be considered a risk. [93] FortisBC also notes that business risk and financial risk come into play in the determination of a fair return through a comparison with other utilities such as Mr. Coyne's analysis as part of the Application.[94]

FortisBC explains that both business risk and financial risk impact capital structure, as the BCUC has historically given substantial weight to business risk, and more particularly, changes in business risk, to justify its capital structure determinations for both FEI and FBC.[95] As such, FEI and FBC demonstrate how the changes in each utility's business risks justify FEI and FBC's proposed common equity ratios.

FortisBC also addresses financial risk in its submissions and the importance of maintaining FEI's and FBC's credit ratings, and provides evidence as to why weak financial metrics can result in negative rating action.[96] As Mr. Coyne explains, a more highly leveraged company requires higher net income to cover its fixed interest obligations, which must be paid before there is any net income for shareholders.[97] FortisBC explains, in addition to business risk, financial risk and credit ratings determine the utilities' ability to attract capital and maintain each utility's financial strength.[98]

Dr. Lesser describes under the semi-strong form of the Efficient Market Hypothesis that prices paid for different types of securities – both debt and equity – must reflect all relevant publicly available information available to investors. This also requires that all perceived risks are taken into account by investors. As part of the decision-making process, Dr. Lesser states, investors as a class must be aware of or have efficient access to all publicly available information, including bond ratings and rating agency reports, equity ratings and discussions by ratings agency reports, and the various methodologies used to determine the cost of debt and equity as contained in the finance literature.[99]

Dr. Lesser and Mr. Coyne both agree that if perceived risks are commonly believed, those risks will be relevant to the calculation of expected returns. Mr. Coyne also notes that looking at the last five years would show real risks that have come to fruition.[100] Mr. Coyne states that overall and taken together, business risk and financial risk are the primary elements of risk that investors consider when establishing their return requirements.[101]

Given the impact of business risk on utilities' expected return, the Panel will review this from the perspective of the shareholder, as it is an important consideration for investors when making their investment decisions. This is

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[93] Exhibit B1-8-1, p. 2.
[94] Exhibit B-1, p. 2.
[95] Exhibit B1-8, p. 5.
[96] Ibid.
[97] Exhibit B1-8-1, Appendix C, p. 73.
[98] Exhibit B1-8, p. 25.
[99] Oral Hearing Transcript, Volume 4, p. 474, Exhibit B1-40, p. 15.
[100] Oral Hearing Transcript, Volume 4, p. 475, Volume 5B, p. 914.
[101] Exhibit B1-8-1, Appendix C, p. 73.

consistent with the BCUC's view of risk in the 2013 Decision,[102] as the probability that future cash flows will not be realized or will be variable, resulting in a failure to meet investor expectations.[103]

Part of this Panel's review includes investors' consideration of credit ratings and whether this has an impact on the Panel's overall determination of ROE and capital structure. The Panel notes that, while this section focuses on business risk, the related financial risk is addressed in Section 6.0 where the Panel makes its overall determinations on ROE and capital structure.

Therefore in this section, the Panel will focus on the following issues:

1. The importance of credit ratings and whether they ought to be an input in the overall determination on ROE and capital structure; and
2. Whether business risk has changed from an investor and shareholder's perspective for FEI and FBC.

4.1 Credit Ratings

Overview

Credit ratings take into account business and financial risks and can provide a broad measure of investment risk for investors.[104]

In determining whether specific credit ratings are to be maintained, credit rating agencies may take into account such factors as evolving concerns regarding energy transition impacts, as well as the utility's financial leverage. Credit ratings can affect a utility's access to debt, as well as its ability to earn a fair return, which may be supported (or countered) by sudden changes in credit ratings. For example, a significant downgrade in credit rating could impair the financial integrity of the utility by reducing its ability to maintain credit and access capital on reasonable terms.[105] Specifically, credit ratings can drive the cost of debt, whereby a higher credit rating is associated with a lower cost of debt and vice versa.[106]

In the 2013 Decision, the BCUC noted there were advantages to establishing an ROE and capital structure which would allow for existing investment grade rating to be maintained but also noted this may result in a capital structure or ROE that is suboptimal in the circumstances. The BCUC in the 2013 GCOC proceeding, supported the maintenance of an investment grade credit rating but only to the extent that it could be maintained without going beyond what is required by the Fair Return Standard.[107] Therefore, The Panel in this proceeding needs to determine the importance it should place on the maintenance of a credit rating when establishing the utility's capital structure and ROE.

Mr. Coyne has included credit ratings as part of his screening test for proxy groups in this proceeding, requiring an investment grade credit rating to ensure that the proxy group companies, like FEI and FBC, are in "sound

[102] BCUC 2013 GCOC Stage 1, Order G-75-13 and Decision dated May 10, 2013 (2013 Decision).
[103] 2013 Decision, p. 24.
[104] Exhibit B1-8-1, Appendix C, p. 43.
[105] 2013 Decision, p. 48.
[106] Exhibit B1-13, RCIA IR 2.2.1 and 4.1.2.
[107] 2013 Decision, pp. 48–50.

financial condition."[108] Credit analysts focus on the potential for default on debt obligations and rate the financial strength of the companies they cover, with BBB from S&P or Baa from Moody's being investment grade.[109] Mr. Coyne specifically screened "credit ratings of at least BBB+ from S&P or Baa1 from Moody's."[110] He notes that credit ratings are commonly used as screens in cost of capital analysis in regulatory proceedings; however, they are "exclusively focused on the risks for debt investors, but do not account for the risks for equity investors."[111]

<u>FEI</u>

FEI is rated by Moody's as of December 2022 and DBRS Morningstar (DBRS) as of March 2021, at A3 (stable)[112] and A (stable),[113] respectively. FortisBC explains that FEI's A level rating ensures that the utility is able to access capital markets on reasonable terms and pricing in most market conditions. FortisBC states, FEI's access to debt capital markets would be more restricted if FEI were downgraded from its current A-level rating to the BBB category rating. If FEI is downgraded to a BBB-category rating, coupled with the fact that FEI is facing increasing scrutiny from investors, credit rating agencies and financial institutions around environmental, social and governance (ESG)-related risks may make it more difficult for FEI to access debt capital markets, especially in times of significant volatility.[114]

Moody's provides the following overview of FEI's profile in its December 2022 Report:[115]

> FortisBC Energy Inc.'s (FEI) credit profile is driven by its low business risk gas transmission and distribution assets that operate in the credit supportive regulatory environment of British Columbia and its monopoly position in its service territory. The company has a long track record of earning its allowed return on equity and its cash flow continues to be highly predictable. These strengths are offset by the company's weak financial metrics that we forecast will be in the range of 11-13% CFO pre-W/C to debt. These financial metrics are primarily a product of a low allowed equity component of its capital structure, a relatively low return on equity, and depreciation rates.
>
> The stable outlook for FEI is based on our expectation of a continuing supportive regulatory environment and consistent, albeit weak, financial metrics that provide limited cushion at the current rating level.[116]

Moody's has also begun to incorporate ESG-related criteria into its credit rating analyses, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change.[117]

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[108] Exhibit B1-8-1, Appendix C, p. 43.
[109] Ibid., Appendix C, p. 117.
[110] Ibid., Appendix C, p. 40.
[111] Exhibit B1-8-1, Appendix C, p. 43.
[112] Exhibit B1-50-1, Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. dated December 9, 2022, p. 1.
[113] Exhibit B1-8-1, Appendix D – 2 Credit Rating Reports, FortisBC Energy Inc. DBRS – 2021 Credit Rating Report.
[114] Exhibit B1-9, BCUC IR 6.3.
[115] Exhibit B1-50-1, Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. dated December 9, 2022, p. 1.
[116] Ibid., p. 2.
[117] Exhibit B1-8-1, Appendix C, p. 80.

Moody's provides an ESG impact score for FEI in its December 2022 Report of moderately negative indicating that FEI's ESG attributes have an overall limited impact on the current rating, with potential for future negative impact over time. Moody's states, the scores reflect high environmental risks, moderate social risks and low governance risks with greatest area of concern being "Environmental."[118] Moody's states that FEI's high environmental risk reflects its elevated exposure to carbon transition risk given BC's legislated commitments to reduce greenhouse gas emissions by 40 percent by 2030 and 80 percent by 2050 and that all of the company's network operations are gas.[119]

DBRS confirms FEI's current credit ratings and notes all trends are stable according to its March 2021 credit report on FEI.[120] FortisBC notes that the confirmations reflect FEI's strong financial and business risk profile and its financial profile remained solid in the last 12 months. Further, DBRS notes that 2021 credit metrics "remained relatively stable and consistent" with its required levels to support the current ratings and "FEI's liquidity was viewed as solid, reflecting stable cash flows, sizable credit facility availability, and the next long-term debt maturity is in 2026."[121]

In addition, DBRS acknowledges that the BCUC has initiated this GCOC proceeding, which will include a review of the deemed equity component of total capital structure and allowed ROE for FEI and other regulated utilities and notes that any material changes in the allowed ROE or deemed equity may affect FEI's credit profile.[122]

Positions of Parties

FortisBC submits that maintaining FEI's existing A-category rating is important for accessing capital on reasonable terms in variable market conditions. Furthermore, an increase in FEI's common equity ratio is required to support its existing credit rating, which is under strain from weak financial metrics, increased weighting for ESG criteria, and potential changes in interest deductibility rules.[123]

Interveners offer differing views on FEI's credit ratings.

The CEC submits that the objective of maintaining the FEI A credit rating is useful and appropriate for FEI customers. Further, the CEC submits that evidence with respect to equity thickness and its impact on credit ratings, "combined with understanding the credit rating process and the consequences for FEI and FBC borrowing and the impacts on customers," leads the CEC to favour increasing the FEI equity thickness, increasing it to 40 percent, and not overreaching on the ROE increases. The CEC submits that "the impact on the credit rating process is more critical than perhaps additional small percentages on the ROE increases."[124] The CEC also notes, "nobody in that 2016 proceeding was using terms like "Energy Transition" or Environmental, Social and Governance (ESG) based investing"[125] and that "[t]here is increasing weight being given by investors to ESG issues."[126]

[118] Exhibit B1-50-1, Moody's Investors Service, Credit Opinion: FortisBC Energy Inc. dated December 9, 2022, pp. 6–7.
[119] Ibid., p. 7.
[120] Exhibit B1-8-1, Appendix D, FEI DBRS Rating Report dated January 5, 2022, p. 1.
[121] Ibid., p. 2.
[122] Ibid., p. 1.
[123] FortisBC Final Argument, pp. 79–80.
[124] The CEC Final Argument, p. 47.
[125] FortisBC Final Argument, p. 24.
[126] The CEC Final Argument, p. 47.

In contrast, BCOAPO argues that the "financial circumstances are not as "dire" as portrayed"[127] and notes that "FortisBC has confirmed that the impact due to changes in regulatory assets could be either up or down in a given year and that the credit rating agencies fully understand this."[128] BCOAPO concludes that much of the business and financial risk associated with the Energy Transition/ESG is already captured by the financial models (e.g. the increased Beta in the CAPM) used to determine the recommended ROE. As a result of the relevant considerations, BCOAPO's recommends an increase in FEI's equity ratio in the range of 40 percent to 42 percent.[129]

In response, FortisBC states that "[t]he primary consideration regarding ESG is not FEI's position relative to other gas companies, but rather the fact that it will be more challenging for FEI to maintain its current rating than it had been in the past given the increasing weight that investors and rating agencies are giving to ESG considerations."[130] FortisBC argues that "FEI needs a stronger balance sheet to counteract this downward pressure."[131] Furthermore, with respect to raising capital, FortisBC explains that FEI's ability has been "facilitated by its existing A level credit rating" and that "[m]aintaining an A level credit rating ensures FEI is able to access capital markets on reasonable terms and pricing in most market conditions."[132]

<u>FBC</u>

FBC is rated by Moody's as of December 2022 and DBRS as of March 2021 at Baa1 (stable)[133] and A (low) (stable),[134] respectively. FortisBC explains that FBC has limited access to the market compared to a larger A-level rated utility, such as FEI, due to FBC's smaller size, its credit rating, and restrictive trust indentures that are sensitive to changes in the cost of borrowing. Therefore, FortisBC states, maintaining FBC's credit rating is critical. If FBC's credit rating is downgraded, its access to capital markets would be further diminished and the pricing and terms for the financing of the debt component of its capital expenditures and operations would become less favourable.[135]

Moody's provides the following overview of FBC's profile in its December 2022 Report:[136]

> FortisBC Inc.'s (FBC) credit profile is driven by its credit supportive regulatory environment and the monopoly position of its stable vertically integrated utility assets. Like affiliate utility FortisBC Energy, Inc. (FEI), the company has a track record of earning its allowed return on equity and its cash flow continues to be highly predictable. This is offset by the company's weak financial metrics, that we forecast will be in the range of 8-10% CFO pre-W/C to debt. These financial metrics are primarily the product of a low allowed equity ratio, a low return on equity, depreciation rates as well as a significant capitalized lease adjustment.

[127] BCOAPO Final Argument, p. 61.
[128] Ibid., p. 61–62.
[129] BCOAPO Final Argument, p. 65.
[130] FortisBC Reply Argument, p. 29.
[131] Ibid., p. 29.
[132] Ibid.
[133] Exhibit B2-8, Moody's Investors Service, Credit Opinion: FortisBC Inc. dated December 12, 2022, p. 1.
[134] Exhibit B1-8-1, Appendix D – 2 Credit Rating Reports, FortisBC Inc. DBRS – 2021 Credit Rating Report.
[135] Exhibit B1-9, BCUC IR 26.1.
[136] Exhibit B2-8, Moody's Investors Service, Credit Opinion: FortisBC Inc. dated December 12, 2022, p. 1.

As with FEI, Moody's has begun to include a ESG score for FBC. As of Moody's December 2022 Report, FBC is rated neutral-to-low because its ESG attributes have a limited impact on the current credit rating. Moody's states, FBC's score incorporates moderately negative environmental and social risks and low-to-neutral governance risks.[137]

Moody's does not have a predominant concern about FBC's ESG considerations but states, FBC's moderately negative environmental risk is driven primarily by its exposure to physical climate risks.[138] Moody's notes that FBC's exposure to social risks is moderately negative, as there is a fundamental risk associated with regulated utilities that demographic and social trends could include social pressure of public concerns around affordability, utility reputational risks or environmental concerns. These pressures could result in adverse political intervention or regulatory challenges.[139]

DBRS states in its March 2021 credit report that the FBC rating reflects FBC's strong financial risk profile and DBRS 's view that the regulatory framework in BC is supportive and stable for FBC's business risk profile over the medium term.[140]

DBRS notes that any material changes in the allowed ROE or deemed equity as a result of GCOC proceedings may affect FBC's credit profile. FBC's credit metrics in 2020 remained solidly supportive of the current ratings and the cash flow-to-debt and interest coverage ratios were consistent with the 2019 levels. DBRS expects FBC's credit metrics to remain stable over the near to medium term. If FBC's credit metrics weaken significantly from the current level on a sustained basis, it could negatively affect the company's ratings. However, DBRS considers this scenario unlikely.[141]

Positions of Parties

FortisBC submits that FBC's financial metrics are very weak for its current rating and are consistent with a non-investment grade credit (i.e. Moody's Ba rating category). FortisBC states, FBC's credit rating is at risk of a downgrade if its financial metrics deteriorate further, which would have significant ramifications for FBC's ability to issue debt on reasonable terms and price. FortisBC submits that key determinants of FBC's weak financial metrics are the low allowed equity component of its capital structure and low return on equity.[142]

Interveners offer differing views on FBC's credit ratings.

The CEC accepts the need for FBC to maintain its credit rating and submits that the proposal to maintain its equity thickness at 40 percent is reasonable. The CEC acknowledges that a downgrade of FBC's credit rating would diminish its access to capital markets and to favourable prices and terms of financing for its debt issuances, as FBC has smaller and less frequent requirements to raise capital, which causes it to not be in the bond index. These issues contribute to weaker demand and lower liquidity for FBC bonds.[143]

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[137] Exhibit B2-8, Moody's Investors Service, Credit Opinion: FortisBC Inc. dated December 12, 2022, p. 6.
[138] Ibid., p. 7.
[139] Ibid.
[140] Exhibit B1-8-1, Appendix D, DBRS FBC Rating Report dated March 15, 2021, p. 1.
[141] Ibid., p. 2.
[142] FortisBC Final Argument, p. 116.
[143] The CEC Final Argument, pp. 49–50.

BCOAPO states that it does not accept that there is any evidence that FBC's business risk or its financial risk is as significant as FBC and Mr. Coyne would have parties believe. However, BCOAPO submits that due to FBC's weak credit rating, it accepts Mr. Coyne and FBC's recommendation that the deemed equity ratio be set at 40 percent.[144] BCOAPO states that in FBC's case, there is little discussion regarding the implications of ESG considerations on the company's access to capital and Mr. Coyne's evidence indicates that FBC would fall at the lower end of the carbon intensity spectrum. As a result, BCOAPO expects "that this characterization will continue to exert a positive, or at worst, a neutral influence in terms of FBC's access to capital, negating any concerns from an ESG perspective."[145]

ICG states that Mr. Coyne opines that FBC's core credit ratios provide little cushion for FBC to maintain its current long-term issuer rating of Baa1 from Moody's. However, ICG notes that the credit report filed as part of FortisBC's Undertaking No. 3 confirmed all FBC credit ratings and concluded that the credit metrics in 2021 remained solidly supportive of the current ratings. ICG states that the report acknowledges if FBC's credit metrics weaken on a sustained basis, it could negatively affect the company's ratings, but notes that this scenario is unlikely and FBC's financial profile remained stable and strong in 2021. ICG submits that this contradicts submissions in FortisBC's Final Argument where it states that FBC's financial metrics are now weak to the point of being generally inconsistent with its current rating.[146]

In response, FortisBC states, the Fair Return Standard requires more than meeting the lowest common denominator; a utility should be able to attract capital on reasonable terms, and financial integrity is also a relevant consideration. FortisBC submits that FBC is facing risk of a downgrade. FortisBC states that most of FBC's financial metrics are consistent with a non-investment grade credit rating, which if applied to FBC, would be a significantly pervasive and profoundly negative development for the utility and customers, as investors generally do not invest in non-investment grade entities, and raising capital would become extremely difficult for FBC.[147]

Panel Discussion

In determining an appropriate ROE and capital structure for FEI and FBC, the Panel considers that it should be careful not to adversely affect each utility's current credit ratings because investors view credit ratings as reflective of the credit rating agencies' assessment of their business and financial risks and hence, the riskiness of such investments.

The Panel is aware that both debt and equity investors, in particular institutional investors, rely on credit rating agencies' reports, which are readily available and updated regularly, to inform them about the wisdom of maintaining, reducing or increasing their respective investments. Furthermore, the Panel accepts FEI and FBC's submission that a lowering of credit agency ratings can raise concerns for potential investors about the utilities' cost of debt and access to the credit market at reasonable cost. Therefore, there are advantages to establishing an ROE and capital structure which will allow for the utilities' existing credit agency ratings to be maintained and

[144] BCOAPO Final Argument, p. 70.
[145] BCOAPO Final Argument, p. 68.
[146] ICG Final Argument, pp. 16–17.
[147] FortisBC Reply Argument, p. 39.

avoid eroding each utility's ability to access capital at reasonable cost.[148] Simply put, investors view credit ratings as reflective of the utilities' relative financial health and ability to access capital at a reasonable cost.

The BCUC must ensure that the entities it regulates maintain the ability to access capital at a reasonable cost to enable such entities to continue to finance company operations and make the necessary capital investments to maintain and upgrade company systems. Our goal is to have financially sound utilities operating in the province so as to avoid a worst case scenario in which a utility defaults because it is not able to access capital at a reasonable cost. We do not consider that allowing such a scenario to unfold is in the interest of the utility, ratepayers or the public. Accordingly, in establishing an appropriate ROE and capital structure for the utilities, we must strive to strike the right balance between debt and capital which does not result in a credit rating downgrade for the utility.

We observe that generally speaking, both FEI and FBC have relatively sound and stable credit ratings, notwithstanding concerns about increasing Energy Transition and ESG impacts in the case of FEI and weak financial metrics in the case of FBC as we discuss in the following two subsections. In setting the ROE and capital structure for each utility, we consider it prudent not to take any action that would directly or indirectly have an adverse impact on either FEI or FBC's current credit ratings, as that would drive up each utility's cost to access capital which in turn is likely to result in rate increases for FEI and FBC customers.

However, assuming the ROE remains the same and all else equal, as long as we do not decrease FEI or FBC's current equity component, we view the risk of a credit rating downgrade to be unlikely in the circumstances. Similarly, all else being equal, any increases in FEI or FBC's equity component that we may approve as a result of this proceeding are likely to improve the financial health and viability of the utilities to the mutual benefit of the utilities' shareholders and ratepayers.

In this case, FEI and FBC's current credit ratings are satisfactory for maintaining the financial integrity of the respective utility and do not require an improvement for each utility to be able to continue to attract capital on reasonable terms. Therefore, the Panel does not view the utilities' credit ratings *per se*, unlike business risks, as a relevant input that would warrant a higher or lower ROE or change in capital structure in these circumstances.

4.2 FEI Business Risk

FEI's business risk was last reviewed in the FEI 2016 Cost of Capital (FEI 2016 COC[149]) proceeding.[150] In its evidence here, FEI provides an overview of its business risks across nine categories: two of which it considers to be of similar risk-level since the FEI 2016 COC proceeding and the remaining seven of which it considers to be of higher risk. FEI used the same categories in the FEI 2016 COC proceeding, other than the Indigenous Rights and Engagement risk factor, that has now been promoted to its own risk category.[151] Additionally, some of the existing risk categories have new risk factors: energy supply renewable gas supply factor and operating attitudes towards fossil-fuel industry, municipal operating challenges, and cybersecurity. FEI notes, while all of the risk categories are important contributors to its overall business risk, political risk and regulatory risk have the

[148] 2013 Decision, p. 48.
[149] FBC Application for its Common Equity Component and Return on Equity for 2016 proceeding.
[150] Exhibit B1-8, p. 2.
[151] Exhibit B1-8-1, Appendix A, p. 1.

greatest potential to affect FEI's ability to earn its return on, and of, invested capital.[152] FEI summarizes its risk as follows:[153]

> The risk factor analysis demonstrates that FEI's overall business risk is significantly higher in comparison to the 2016 Proceeding for two reasons. First, most categories present higher risk since the 2016 Proceeding. Second, political and regulatory risk, which are both higher due in large measure to the Energy Transition, are the risk categories where changes presently have the greatest potential to affect FEI's ability to earn its return on, and of, invested capital.

Table 9 below provides a summary of this risk assessment.

Table 9: Summary of FEI's Business Risk[154]

Business Risk Category	Risk Factor	Change in Risk Since 2016
Business Profile		**Similar**
	Type and size of the utility	Similar
	Service area	Similar
	Customer profile	Higher
Economic Conditions		**Higher**
	Overall economic conditions	Higher
Political		**Higher**
	Climate action goals and expectations	Higher
	Energy policies and legislation	Higher
Indigenous Rights and Engagement		**Higher**
	Legislative and policy developments	Higher
	Aboriginal rights and title	Higher
	Social license/work interruption	Higher
Energy Price		**Higher**
	Commodity price	Higher
	Commodity price volatility	Higher
	Price competitiveness and carbon tax	Higher
Demand/Market		**Higher**
	Perception of energy	Higher
	New technology and energy forms	Higher
	Net customer additions	Higher
	Changes in building type and capture rates	Similar
	Changes in end-use market share	Higher
	Changes in use per customer	Similar
Energy Supply		**Similar**
	Availability of supply	Similar
	Access to supply	Similar
	Renewable Gas supply	New (Higher)
Operating		**Higher**
	Aging infrastructure and time dependent threats	Similar
	Third party damages	Similar
	Attitudes towards fossil-fuel industry	New (Higher)
	Municipal operating challenges	New (Higher)
	Cybersecurity	New (Higher)
	Unexpected events	Higher
Regulatory		**Higher**
	Regulatory uncertainty and lag	Higher
	Administrative penalties	Similar

[152] Exhibit B1-8-1, Appendix A, p. 2
[153] FortisBC Final Argument, p. 32.
[154] Exhibit B1-8-1, Appendix A, pp. 2–3.

While energy transition is not included as its own risk category in FEI's risk assessment, it covers a broad spectrum of risks that are transforming gas utilities' risk profiles in North America,[155] and therefore is discussed before the other risk categories, as it has implications for many of the other categories.

The sections below review each of the business risk categories and the positions of parties. To provide a comprehensive discussion, the Panel addresses all submissions received pertaining to FEI before making its overall findings and determinations on changes in FEI's business risk since the FEI 2016 COC proceeding.

Energy Transition

FortisBC reports the increasing pace of the energy transition from fossil fuels to cleaner sources of energy through electrification of the economy, and increased recognition of the effect of this transition on natural gas utilities by utility analysts and investors, represent what Concentric refers to as a "transformation of long-term risk environment" for natural gas utilities across North America.[156] FortisBC explains that the term "Energy Transition" risk is a new umbrella term which covers that spectrum of risk.[157]

FortisBC states that this risk is apparent in the provincial government's recently updated CleanBC Roadmap to 2030 (Roadmap) which establishes a greenhouse gas reduction obligation for natural gas utilities to reduce emissions from energy delivered to the buildings and industrial sectors. The Roadmap is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for FEI's customer rates and throughput. FortisBC has characterized the policy developments associated with the Energy Transition as political risk, but also states that these developments impact other risk categories since the FEI 2016 COC proceeding such as Indigenous Rights and Engagement, demand/market, regulatory, operating, and economic conditions risks.[158]

Mr. Coyne notes that the Energy Transition creates stranded asset risk for FEI by introducing the possibility that significant portions of FEI's assets will cease being used and useful before being fully depreciated, which could impact growth prospects or profitability of FEI's operations.[159] Mr. Coyne also notes that although according to S&P, "[s]tranded costs have not up until now been an issue for gas local distribution companies," concerns about stranded assets have spiked recently, "[c]hallenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond."[160]

Dr. Lesser also considers Energy Transition risk to be primarily a regulatory/policy risk because companies are required to meet specific policy goals. The risks of meeting those goals can then result in secondary business and financial risks (e.g. cost-overruns associated with a new technology and stranded asset costs), depending on how regulators treat the companies' efforts to meet those regulatory/policy goals. Dr. Lesser notes that there is an inherent circularity in how Energy Transition risk should be treated. If, for example, legislators pass a law guaranteeing recovery of all potential stranded costs that may arise from the Energy Transition, then there is

[155] Exhibit B1-9, BCUC IR 4.1.
[156] Exhibit B1-8, p. 3.
[157] Exhibit B1-9, BCUC IR 4.1.
[158] Exhibit B1-8, p.3; Exhibit B1-8-1, Appendix A, p. 4.
[159] Exhibit B1-8-1, Appendix C, pp. 73, 90.
[160] Ibid., p. 90.

little additional financial risk to the utility. But if regulators are hostile to stranded cost recovery, then financial markets may require a premium to provide funds to the utility.[161]

Positions of Parties

BCOAPO submits that Energy Transition also includes elements of risk associated with Price (e.g. carbon taxes), Regulatory (e.g. increased complexity and need for flexibility) and Supply (e.g. issues related to Renewable Gas). BCOAPO accepts that political considerations driven by climate change are the impetus behind the risks associated with Energy Transition. However, to the extent current implemented policies addressing climate change concerns are identified and assessed in the consideration of the risks associated with FEI's other risk categories, such policies should not also be identified as political risk. [162]

The CEC submits, "the Energy Transition risks are real and moving quickly in BC" and the BCUC "needs to give significant weighting to the importance of the existential issues facing FEI."[163] However, the CEC finds FEI's risk analysis to be overstated and expects that FEI' s risk will be largely mitigated by new technologies and future developments.[164] Further, the CEC suggests there may be value in separating "the Energy Transition issue out when assessing FEI' s business risk, and evaluate this risk independently against time and other comparable utilities in Canada and the US, instead of addressing it in multiple areas and muddying the other analyses."[165] The CEC submits that it might be appropriate and in the public interest for the BCUC to determine an established risk factor that can be incorporated into FEI' s financial analyses to account for stranded asset risk.[166]

RCIA explains that the issue of Energy Transition "is not new" and "will be with us for a long time."[167] RCIA submits that FortisBC's business risk narrative identifies the same underlying challenges (e.g. climate change policies) as multiple different business risks. RCIA argues that FortisBC exaggerates the depth and breadth of those risks, as it fails to consider to what extent the various risks are duplicative, overlapping or are simply unlikely to result in any material and unrecoverable losses.[168]

MoveUP advocates for "explicit recognition" of diverging impacts, risks and opportunities arising between electric and gas utilities and that this is "foundational to achieving an orderly and rational response to evolving climate policy, including electrification."[169] MoveUP submits that unless carefully calibrated, increasing a gas utility's ROE to manage transition risk could potentially magnify risk and be self-defeating in the longer term.[170]

In reply, FortisBC states that Energy Transition represents a fundamental change that has a pervasive impact on FEI's business.[171] Additionally, FortisBC submits that the Energy Transition is a "notable" area "where BC is markedly different," and where FEI's risk has increased the most since the FEI 2016 COC proceeding.[172] More

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[161] Exhibit A2-24, BCOAPO IR 14.3 and 14.4.
[162] BCOAPO Final Argument, p. 15.
[163] The CEC Final Argument, p. 48.
[164] Ibid, p. 28.
[165] Ibid., p. 11.
[166] Ibid., p. 3.
[167] RCIA Final Argument, p. 30.
[168] Ibid., p. 4.
[169] MoveUP Final Argument, pp. 1–2.
[170] Ibid., p. 2.
[171] FortisBC Reply Argument, p. 17.
[172] Ibid., p. 15.

details of FortisBC's reply to intervener arguments on Energy Transition risk are presented under individual risk categories below.

Business Profile

Business profile risk, as defined by FortisBC, is determined by analyzing the type and size, service area, and customer profile of a utility, which are its fundamental characteristics.[173] FortisBC explains that FEI's primary market continues to be residential and commercial space and water heating end-uses. Further, despite some shift in load to the more volatile / sensitive industrial and low carbon transportation sectors, FEI assesses its overall business profile risk to be similar to that in the FEI 2016 COC proceeding.[174]

Positions of Parties

BCOAPO and the CEC agree with FortisBC's business profile assessment.[175]

Economic Conditions

FortisBC assesses that the current Canadian economic environment continues to be dominated by uncertainty and explains that "the record high inflation rate, caused by government fiscal and monetary policy to boost economic growth and improve employment, and BC's challenges for long-term economic growth points to higher risk."[176] Mr. Coyne also comments that the war in Ukraine, aggressive federal action on interest rates, historic high levels of inflation, and pull back on the fiscal stimulus required to support the pandemic ailing economies in Canada and the US have had significant impacts on capital markets in 2022.[177] However, FortisBC does explain that FEI's operations and maintenance (O&M) expenditures and growth capital are indexed to a composite inflation factor (minus a productivity factor of 0.5 percent) and are less impacted by high inflation rates, but FEI's sustainment capital is forecast.[178] FortisBC also notes that utility stocks are generally characterized as defensive and most investors holding utility stocks expect that utility earnings remain stable and grow slowly in most economic conditions.[179]

Positions of Parties

BCOAPO agrees that there is both greater uncertainties associated with the economic outlook for BC (and Canada), particularly in the short-term, and lower prospects for longer term growth.[180] However, the CEC recommends that the BCUC assign no weight to 'Economic Conditions' as a risk factor, as the CEC submits that almost all these items may all be considered as undiversifiable risk. The CEC states that there is little evidence to support a finding that FEI experienced economic woes to a greater extent than those of other utilities, and that this should be considered as conjecture at best.[181]

[173] Exhibit B1-8-1, Appendix A, p. 8.
[174] Ibid., pp. 3–4.
[175] BCOAPO Final Argument, p. 14, The CEC Final Argument, p. 13.
[176] Exhibit B1-8-1, Appendix A, p. 4.
[177] Transcript Volume 3 – Proceedings November 7, 2022, p. 158.
[178] Exhibit B1-9, BCUC IR 13.1.1.
[179] Ibid., BCUC IR 21.1 and 21.1.1.
[180] BCOAPO Final Argument, p. 14.
[181] The CEC Final Argument, pp. 13–14.

In response, FortisBC argues that similar macro-economic conditions can still lead to different impacts on different utilities based on the particular characteristics of the utility and its jurisdiction.[182]

Political

FortisBC considers political risk to be "the most notable of all of the risk factors."[183] FortisBC explains that government policies and regulations at all levels, as well as stakeholder interests, have a significant impact on FEI's operations, competitiveness, and ability to achieve its important initiatives. Additionally, FortisBC stresses, "[t]he overall thrust of climate change and energy policies is moving at a more rapid pace than at the time of the 2016 Proceeding and the role of natural gas, or even Renewable Gas, within the province's future energy landscape is unclear."[184]

While FEI believes that gas infrastructure is an optimal tool to reach decarbonization goals, there is a lack of awareness and acceptance of that role, given it is not directly discussed in net zero climate goals and plans. FortisBC states that this is apparent in the provincial government's recently updated Roadmap which is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for customer rates and throughput. FortisBC states that the risk is further compounded by the fast pace of legislation and policies on electrification initiatives which increase competition with electricity. FortisBC assesses that FEI's political risk has increased significantly relative to the political risk environment at the time of the FEI 2016 COC proceeding.[185]

Positions of Parties

BCOAPO accepts that political risk faced by FEI has increased, primarily because governments are now clearly paying attention to and responding to climate change concerns, and acknowledges that there is also political risk associated with the lack of government direction regarding the role BC gas utilities will play in addressing climate change concerns.[186] BCOAPO views that "the critical aspect regarding political risk is the uncertainty regarding future policies and the impact they will have on FEI's business."[187] The CEC agrees that there is a growing bias against the use of natural gas on the part of multiple policymakers. The CEC suggests, there should be consideration for other political risks such as the "significant political upheaval in the US over the last few years"[188] and that it is important that the BCUC not overlook other aspects of the political environment when considering FEI' s political risk.[189]

With respect to the CEC's arguments regarding political upheaval in the US, FortisBC submits that the "BCUC should not consider the new and untested information. In any event, the link between political upheaval in the US and policies around the Energy Transition are not immediately apparent."[190]

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[182] FortisBC Reply Argument, p. 18.
[183] Exhibit B1-8-1, Appendix A, p. 4.
[184] Ibid.
[185] Ibid.
[186] BCOAPO Final Argument, pp. 15–16.
[187] Ibid.
[188] The CEC Final Argument, p. 16.
[189] Ibid., p. 17.
[190] FortisBC Reply Argument, p. 19.

RCIA states that FEI's business risk narrative identifies the same underlying challenges (i.e. climate change policies) as multiple different business risks, which RCIA notes, does not provide clear, objective evidence validating an absolute increase in business risk.[191] RCIA submits that climate change and related topics have been part of the public discourse for many years and is not a new issue.[192] In reply, FortisBC states that FEI has not claimed that policy risk is new per se, but rather has demonstrated that the risk is significantly higher than at the time of the FEI 2016 COC proceeding.[193]

Indigenous Rights and Engagement

FortisBC has assigned Indigenous Rights and Engagement risk its own category in this proceeding (previously subsumed under political risk) to reflect the increasing significance of these considerations for FEI's overall business. This risk assesses the potential for utility operations to be impacted by policy or legislation concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. As provincial and federal governments navigate reconciliation and implement the UN Declaration on the Rights of Indigenous Peoples, FEI has assumed a higher level of business risk related to its relationship with Indigenous groups compared to what it anticipated at the time of the FEI 2016 COC proceeding.

FortisBC explains most land in BC is not subject to treaty (the land is unceded), and most Indigenous groups in BC are not signatories or adherents to a treaty (historic or modern) unlike in many other provinces. FortisBC states that Indigenous groups in BC are diverse and the added uncertainty from outstanding claims to Aboriginal title and rights further complicates the landscape within which FEI operates. Most of FEI's operations are in areas not covered by treaty, meaning that these areas are subject to assertions of Aboriginal title and may be subject to legal claims for title in the future. However, FEI also has some operations in treaty areas. Combined with regulatory updates that have increased consultation requirements and include a focus on seeking consensus and consent of Indigenous groups, as well as the risk of litigation in the absence of consent, FEI considers that it faces an elevated risk of cost escalation, project delays, and/or projects being denied approval.[194]

Positions of Parties

BCOAPO agrees that FEI faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of the FEI 2016 COC proceeding. However, BCOAPO notes that FEI has not been a party to any litigation initiated by Indigenous groups based on the duty to consult in either the five-year period prior to or since the FEI 2016 COC proceeding and has not faced any formalized work disruptions (e.g. protests or blockades) initiated by Indigenous groups, and no projects have been denied as a result of issues regarding the duty to consult with Indigenous groups. Similarly, FEI is not currently involved in any judicial reviews based on claims of inadequate consultation or other Indigenous rights litigation.[195]

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[191] RCIA Final Argument, p. 31.
[192] Ibid., pp. 29–30.
[193] FortisBC Reply Argument, p. 20.
[194] Exhibit B1-8-1, Appendix A, pp. 4–5, 44.
[195] BCOAPO Final Argument, p. 17.

BCOAPO also highlights that FEI has mitigation in place as it actively addresses the risks associated with its increased duty to consult by reaching out to Indigenous groups early (sometimes in absence of a Crown determination), as "FEI's goal is to engage early, often, and thoroughly."[196] BCOAPO is also concerned that there is overlap and double-counting with FEI's Regulatory risk, differentiating that "the duty to consult on projects (prior to making applications to regulatory bodies) should be considered an Indigenous Rights and Engagement risk, while the increase in interventions and participation by Indigenous groups in regulatory processes should be considered a Regulatory risk."[197]

In response to BCOAPO, FortisBC states that its business risk assessment already accounts for mitigation and investors are aware of publicly available information, including plans, strategies and capital investments that would mitigate the utilities' risk.[198] In regards to double-counting and overlap, FortisBC states its risk analysis is a holistic assessment of a complex matrix of factors affecting different aspects of FEI and FBC's businesses, and FortisBC has never suggested that the BCUC's role is to carry out a rote tallying of categories.

FortisBC explains investors will inevitably approach risk assessment in different ways, but the ultimate objective will always be to assess the potential for not earning a return on and of invested capital. The risk categories that FortisBC has employed are a useful presentation format for identifying the types of considerations that inform investment decisions and are consistent with the categories and factors used in previous cost of capital proceedings, thus facilitating comparisons over time.[199]

The CEC recommends that the BCUC find the Indigenous Rights and Engagement concerns to be largely mitigatable and less risk than that in 2016. The CEC submits that many utilities face issues with respect to Indigenous Rights and Engagement issues, and so the risk may be somewhat undiversifiable. The CEC argues that provincial policy has been made clearer, given certain pronouncements mandating steps to entities dealing with Indigenous Peoples which were not clearly mandated in 2016.

The CEC notes that there has been considerable movement regarding Indigenous Peoples for engaging in reconciliation activities and the CEC expects that this may turn from being a risk increase to being a positive reduction of risk.[200] The CEC also submits that this category should be included in the political category as it was previously. The CEC states that it is important for the BCUC to exercise caution when separating out items that were previously considered together, in that it potentially leads to selection or framing bias, and weighting becomes more difficult.[201]

In response to the CEC, FortisBC argues that utilities in BC are exposed to unique risks because, unlike in other provinces, most land is not subject to treaty (the land is unceded), and most Indigenous groups in BC are not signatories or adherents to a treaty (historic or modern). [202] Further, FortisBC's "commitment to developing meaningful relationships with Indigenous communities cannot fully mitigate risk, and FEI's risk assessment is post-mitigation."[203] FortisBC argues that business uncertainty associated with Indigenous Rights and

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[196] BCOAPO Final Argument, p. 18.
[197] Ibid., p. 17.
[198] FortisBC Reply Argument, p. 11.
[199] Ibid., p. 5.
[200] The CEC Final Argument, p. 18.
[201] Ibid., p. 17.
[202] FortisBC Reply Argument, pp. 20–21.
[203] Ibid.

Engagement has increased since the FEI 2016 COC proceeding.[204] Finally, FortisBC submits that trying to recategorize risks at this point would be counter-productive.[205]

Energy Price

FortisBC states the risk relating to energy prices is higher than what it was during the FEI 2016 COC proceeding. FortisBC explains that energy prices impact a utility's business risk because price is among the factors that can influence consumer energy choices. It argues that FEI's overall energy price risk is higher due to:[206]

- Natural gas commodity prices being higher: Current market prices for natural gas are higher than in 2015 and forecasted to increase as demand from power generation and liquefied natural gas (LNG), and a potential decline in crude oil production, puts pressure on prices;
- Natural gas prices being more volatile: Market prices are expected to remain volatile as a result of extreme weather events, changes in natural gas demand for power markets in the region, and anticipated growth in demand to supply the LNG export market. The volatility is greater than that presented in the FEI 2016 COC proceeding; and
- Subsidies and tax incentives / disincentives making electric appliances cheaper than gas appliances: The current price advantage of natural gas versus electricity is not expected to be maintained, especially with recent rate announcements from BC Hydro which will see electricity rates held fairly flat over the next several years. Current and planned increases in carbon tax rates will continue to negatively affect natural gas price competitiveness relative to electricity.

Further, the increasing share of higher cost Renewable Gas in FEI's gas supply portfolio contributes to FEI's higher price competitiveness risk as Renewable Gas is more expensive than natural gas. Moreover, new technology which supports the use of electricity, such as electric heat pumps, that have a higher upfront and installation cost than natural gas-fired equipment, are more cost competitive when government-provided incentives and rebates are considered.[207]

Positions of Parties

BCOAPO agrees that FEI's energy price risk has increased since the FEI 2016 COC proceeding. However, based on BCOAPO's view that natural gas commodity risk is similar to that in 2015 for the long term, BCOAPO does not view FEI's energy price risk as having increased to the same degree as suggested by FEI.[208] BCAOPO notes that when natural gas commodity prices are looked at in real terms (i.e. adjusted for inflation) current commodity prices are high relative to those in 2015. However, forecast commodity prices (post 2023) are in line with those from 2015 to 2016. However, BCOAPO does agree with FortisBC with respect to increased natural gas price volatility and decreased competitiveness.[209]

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[204] FortisBC Reply Argument, p. 21.
[205] Ibid., p. 6.
[206] Exhibit B1-8-1 Appendix A, pp. 53–78.
[207] Ibid., pp. 5, 70.
[208] BCOAPO Final Argument, pp. 18–19.
[209] Ibid., p. 19.

In reply, FortisBC submits that BCOAPO's attempt to downplay the risk is incongruous with its acknowledgement that current commodity prices are high relative to those in 2015 and its agreement about increased price volatility and decreased competitiveness.[210]

The CEC recommends that the BCUC finds the energy price risk to be similar to 2016 and assign limited weight to energy price as a risk category. The CEC does not agree that an increase in natural gas price will necessarily equate to an increase in the risk that the company will not recover its ROE, as the higher price is caused by increasing demand. The CEC submits that "this approach to assessing risk is not consistent with the definition of risk as it relates to achieving ROE but is rather FEI's shotgun and 'general impression' approach to including any number of possible items without refining the analysis to assess whether or not it actually results in risk to the utility in its ability to achieve its ROE."[211]

The CEC accepts that price competitiveness and the narrowed cost differential with electricity potentially represent something of a higher risk. However, the CEC submits that the cost of adding renewable natural gas supply to the portfolio should be treated as a mitigating factor with respect to the effects of the Energy Transition and will likely serve to mitigate the political, regulatory and customer risk. Finally, the CEC expects volatility may have little impact on the ability of the utility to recover its ROE.[212]

In reply to the CEC, FortisBC argues that FEI is purchasing more renewable gas to mitigate its Energy Transition risk, but that does not mean its energy price risk is not higher because of it. FortisBC states, FEI is not required to demonstrate that it will not recover its ROE, but rather, in the long term, investors would perceive risk to the recoverability of their invested capital from an increase in the risk related to energy price. FortisBC submits that the CEC is "conflating investor-perceived risk (the relevant consideration in cost of capital analysis) with actuarial risk (an irrelevant consideration)."[213]

MoveUP submits, as gas commodity and delivery costs increase relative to electricity, more customers will prefer electric energy solutions, adding yet another accelerator to declining customer growth and a core customer base will be left to bear the utility's fixed costs and return on its invested capital. Responding to this risk cycle by increasing ROE without regard to these impacts would add fuel to the fire. MoveUP states that the BCUC must be mindful of the rate impacts of risk-based increases in gas utilities' rates of return to avoid a dynamic where satisfying immediate return entitlements accelerates a potential capital funding crisis over time. MoveUP argues that rewarded capital today could become stranded capital earlier in the future.[214]

In reply to MoveUP, FortisBC explains that all rising costs, not just increasing cost of capital, affect a utility's competitiveness; all prudent costs of providing utility service, including cost of capital, must be recovered. FortisBC submits that FEI needs to be well-financed to navigate the Energy Transition and encouraging the flight of capital away from a capital-intensive business is a poor recipe for success.[215]

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[210] FortisBC Final Argument, p. 21.
[211] The CEC Final Argument, pp. 19–20.
[212] Ibid., p. 20.
[213] FortisBC Reply Argument, p. 22.
[214] MoveUP Final Argument, p. 3.
[215] FortisBC Reply Argument, pp. 3–4.

Demand/Market

FortisBC states overall, since the FEI 2016 COC proceeding, FEI's demand/market risk has increased. FortisBC states that customer energy choices have had the tendency to be driven by market factors such as energy price, accessibility, ease of use, reliability, and availability. However, FortisBC explains that demand and market changes pose challenges to FEI's ability to attract and retain customers and maintain market share and throughput levels driven by:[216]

- BC residents' worsened perception of natural gas as customers' energy choices are increasingly influenced by a desire to minimize negative environmental impacts;
- New technologies and building techniques, supported by policies that are negatively affecting gas demand;
- While Renewable Gas can be a relatively affordable option, the electric options such as high-efficiency heat pumps are gaining faster and more widespread traction among customers and policy makers;
- FEI experiencing a downward trend in net residential customer additions and in its share of natural gas use in space heating and water heating applications;
- In the residential sector, where due to BC's high turnover rate, a large segment of its existing customers' homes may be torn down and rebuilt with electric-only options to meet more stringent code requirements;
- FEI's risk profile which continues to be impacted by the gradual decline in single-family dwellings, where FEI has higher capture rates in favour of multi-family dwellings; and
- FEI's new residential customers who continue to have lower use per customer (UPC) than average residential customers do,[217] although this is somewhat offset by load growth in the more volatile and economically sensitive transportation and industrial sectors.[218]

FortisBC states that all of these factors create challenges for natural gas utilities in retaining and attracting load, despite lower natural gas commodity prices relative to other energy forms. [219]

Positions of Parties

BCOAPO submits that FEI's assessment of the increase in risk associated with Market/Demand is overstated.[220] BCOAPO submits that recent trends in UPC have been more favourable than those leading up to the FEI 2016 COC proceeding and argues that increases in UPC for the non-Residential sectors have more than offset any trend to lower UPCs in the Residential sector.[221] BCOAPO views there is overlap (and likely double counting) between the various factors assessed under Market/Demand, as the increased use of electric heat pumps is a consideration for 'New Technology and Energy Forms' but is also a contributor to the risk assessment with respect to 'Net Customer Additions' and 'Changes in end-use Market Share'.[222]

[216] Exhibit B1-8-1, Appendix A, pp. 5, 78–88.
[217] Ibid., p. 5.
[218] Ibid., p. 57.
[219] Ibid., p. 78.
[220] BCOAPO Final Argument, p. 22.
[221] Ibid., pp. 21–22.
[222] Ibid., p. 22.

In reply to BCOAPO, FortisBC submits that in the context of the Energy Transition, the past is not the best predictor of the future and several factors that are expected to impact FEI's market share and UPC, such as electric heat pumps, are expected to reduce UPC, and municipal policy is expected to reduce FEI's ability to connect to new customers.[223]

The CEC recommends that the BCUC find there to be similar risk as those found in 2016 based on the evidence in the FEI Long Term Gas Resource Plan (LTGRP) proceeding and avoid unduly exaggerating the political risk of the Energy Transition when considering this category.[224] Moreover, the CEC notes that declining market share does not necessarily represent declining revenues or an inability for the utility to achieve its ROE and that most of the risk areas identified in demand/market risk are at least largely captured in political risk.[225]

In reply to the CEC, FortisBC submits that FEI's evidence in this proceeding on demand/market risk is consistent with the LGTRP proceeding. FortisBC also submits that a reasonable investor would perceive risk to their prospects of recovery in light of FEI's diminishing market share. FortisBC explains that investors take a long-term view of risk and would negatively perceive declining market share. A smaller customer base generally means that the revenue requirements are recovered from fewer customers over fewer billing determinants. An investor considering long-term risk will realize that this pattern will increase the prospects of further loss of market share and even higher rates (i.e. a spiral).[226]

RCIA submits that expansion opportunities are particularly relevant to FEI's overly conservative projections and that realistically, FEI's revenues could be substantially higher in the near future than they are currently. This windfall opportunity should substantially offset many of the business risks alleged by FEI.[227] RCIA also notes that "FEI's annual demand forecast indicates expected demand over the next 3-5 years (and longer) will be strong, even under worst-case scenarios."[228]

In reply to RCIA, FortisBC states that FEI's primary business continues to be in serving space and water heating load in the residential and commercial sectors. FortisBC submits that focusing only on overall units of energy demand from FEI distracts from the other risk factors affecting the demand/market risk category, including downward changes in end-use market share, downward trends in net customer additions, and increased gas supply costs. These trends are indicative of longer-term risk, which is the focus of risk assessment, not three to five year forecasts. In addition, adding load from LNG to the core residential and commercial sectors to mitigate load losses in exposes FEI to higher revenue (and potentially earnings) volatility.[229]

Energy Supply

FortisBC states, relative to 2015 levels, FEI's energy supply risk remains similar. FortisBC notes that availability and accessibility of natural gas supply to FEI's service territory remain unchanged, as natural gas producers forecast production increases to meet demand growth for gas-fired power generation and LNG. Additionally, FEI

[223] FortisBC Reply Argument, pp. 22–23.
[224] The CEC Final Argument, p. 22.
[225] Ibid., pp. 21–22.
[226] FortisBC Reply Argument, pp. 23–24.
[227] RCIA Final Argument, p. 26.
[228] Ibid., p. 27.
[229] FortisBC Reply Agrument, pp. 24–25.

continues to rely on a single system for a significant portion of its gas requirements.[230] FortisBC has also added a new risk factor to this category, 'Renewable Gas Supply', which it deems as higher change in risk since 2016, albeit there is no change in the overall risk category. FortisBC argues that there is increased risk arising from issues with suppliers, competition for Renewable Gas supply, and barriers to gas system readiness and acceptance of non-local supply.[231]

Positions of Parties

BCOAPO agrees with FEI's risk assessment regarding natural gas commodity supply and access. The CEC recommends that the BCUC find the energy supply risk to be similar to that in the FEI 2016 COC proceeding while assigning moderate weight to this category.[232]

Operating

FortisBC submits that operating risk includes the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography, human error, and weather.[233] FortisBC explains that operating risk factors continue to include infrastructure integrity and time dependent threats, along with third-party damages and unexpected events (including the COVID-19 pandemic, Enbridge T-South pipeline rupture, as well as more frequent extreme weather events).[234] While these types of operating risks have always been present, there is a growing recognition in the industry of utility exposure to significant unforeseen events and the importance of resiliency.[235]

FortisBC acknowledges that there is a risk management process for FEI's reliability and resiliency integrity projects, and it prioritizes the projects based on the importance of managing those risks.[236] Of note, FEI has also added several new risk factors to this category (including attitudes towards fossil-fuel industry, municipal operating challenges, and cybersecurity), which it deems as higher change in risk since 2016 and contribute to the overall risk category assessment as higher.[237]

FortisBC submits that the negative public sentiment towards the fossil-fuel industry may hinder FEI's ability to recruit skilled workers, complete already approved projects on time and budget, meet environmental and safety requirements or obtain the necessary approvals and operating permits. Additional municipal requirements and associated costs arise in the context of both FEI's ongoing operating and maintenance activities and its larger construction projects. These additional requirements may result in increased costs to FEI or challenges requiring additional time to resolve. FortisBC submits that its approach is to manage these additional requirements by negotiating an acceptable compromise with municipalities, and typically, FEI and the municipality are able to reach a compromise, which is consistent with FEI's rights and obligations.[238]

[230] Exhibit B1-8-1, Appendix A, p. 6.
[231] Exhibit B1-8-1, Appendix A, pp. 97–107.
[232] BCOAPO Final Argument, p. 22, The CEC Final Argument, p. 23.
[233] Exhibit B1-8-1, Appendix A, p. 108.
[234] Ibid., p. 6.
[235] Exhibit B1-8, p. 16.
[236] Oral Hearing Transcript, Volume 5B, p. 887.
[237] Exhibit B1-8-1, Appendix A, p. 2–3.
[238] Ibid., p. 111.

Positions of Parties

BCOAPO agrees that FEI's operating risk has increased but not to the degree implied by FEI.[239] BCOAPO notes that there is a potential overlap of contributors in the operating risk category as to FEI's political risk with respect to attitudes towards the fossil-fuel industry, including the province's updated Roadmap, which are increasing concerns around natural gas utility activities and increasingly strict environmental and safety laws, regulations and enforcement policies since 2015.[240] BCOAPO also states that "there is no reference in the evidence presented to a successful cyber-attack on FEI that impacted its operations" and that while BCOAPO "acknowledges that lack of occurrence does not mean a risk does not exist", in BCOAPO's view, "past occurrences do provide an indication as to the degree of risk involved."[241]

In reply to BCOAPO, FortisBC states that the lack of a previous occurrence does not mean a risk does not exist and points to the fact that utilities such as FEI are vulnerable to cyberattacks and the consequences may be severe.[242]

The CEC submits that, overall, the operating risk for FEI is at least similar, if not better, than that during the FEI 2016 COC proceeding due to the new capital projects likely to be undertaken to enhance reliability and resiliency and recommends that the BCUC assign moderate weight to this category.[243] The CEC submits that there are very substantial resources being devoted to mitigating the risks and recommends that the BCUC weigh the value of these risk mitigation and resiliency projects significantly to avoid having ratepayers fund the projects without having the associated risk reduction recognized financially in the setting of the ROE.[244] The CEC "expects that cyber security may be a higher risk, but also notes that this is an undiversifiable risk in that nearly all companies are facing increased issues in this field."[245]

In response to the CEC, FortisBC argues with respect to new projects, FEI's risk assessment is post-mitigation, some of these projects have not yet been approved and implemented, and that cybersecurity risk is "increasingly gaining weight in investors' perception of risk."[246]

RCIA submits that although unpredictable weather is an operational challenge, it is not clear the potential impact of unpredictable weather is a genuine threat to FortisBC achieving its approved ROE or return of capital, as it is not clear that extreme weather events will impede FortisBC's ability to achieve its ROE or that associated costs will not be recoverable through rates or government funding.[247]

In reply to RCIA, FortisBC states that it is not required to demonstrate that each risk factor will impede FEI's ability to achieve its ROE, only that investors would perceive a long-term risk of recovering their investment. Considering FEI's recent experience with a high volume of high-impact weather events, FortisBC submits that a reasonable investor would perceive an elevated level of risk.[248]

239 BCOAPO Final Argument, p. 23.
240 BCOAPO Final Argument, p. 23.
241 Ibid.
242 FortisBC Reply Argument, p. 25.
243 The CEC Final Argument, p. 24.
244 Ibid.
245 Ibid.
246 FortisBC Reply Argument, p. 26.
247 RCIA Final Argument, p. 30.
248 FortisBC Reply Argument, p. 26.

Regulatory

FortisBC states that as a regulated public utility, FEI is dependent on regulators for timely and fair approvals to earn its return on and of capital, which results in regulatory risk.[249] FortisBC explains that there is an increased level of regulatory uncertainty and increased potential for regulatory lag in both BCUC and other regulatory processes.[250] FortisBC has assessed FEI's overall regulatory risk as higher than what was assessed in the FEI 2016 COC proceeding, with certain risk factors increasing and others being similar. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FEI with an opportunity to earn its fair return, or that necessary investments are not approved.

The underlying BCUC regulatory framework remains the same, but there are new developments that merit note. There is uncertainty caused by the level of regulatory support for the implementation of certain initiatives and the BCUC's decision to consider a more generic approach to deferral account financing treatment. FortisBC also mentions there are increased requirements for stakeholder consultation, environmental reviews, Indigenous rights and title, and municipal operating challenges.[251]

Positions of Parties

BCOAPO acknowledges that BCUC has discretion which, inherently, creates risk, but points out that FortisBC has acknowledged that it "generally finds the BCUC's decisions to be well reasoned (irrespective of whether a decision is favourable to FortisBC or not)."[252] BCOAPO submits that "the requirement for seeking the free, prior and informed consent ("FPIC") of Indigenous Peoples before proceeding with project development and, in particular, before proceeding with an application for regulatory approval (from the BCUC or any other approval authority) is a legitimate risk. However, it should not be double counted" and "not included in the assessment of Regulatory risk as FEI has done."[253] With respect to FortisBC's concerns regarding deferral account financing, BCOAPO submits that both FEI and FBC will have a full opportunity to present their views and that "the BCUC is open to considering specific circumstances after it has made decisions on a generic basis."[254]

In response to BCOAPO, FortisBC argues that "the fact a BCUC decision is well-reasoned does not mean the decision will be favourable from an investor's perspective."[255] Furthermore, with respect to double-counting, FortisBC submits that "recategorizing these distinct impacts does not make the risk any less real to investors."[256]

The CEC recommends that the BCUC find the regulatory environment to be generally favourable and the risk similar as in 2016.[257] The CEC submits that there is little regulatory risk associated with a utility not being enabled to earn a fair return and what may be considered as 'generally fair' regulation should not be interpreted

[249] Exhibit B1-8-1, Appendix A, p. 115.
[250] Exhibit B1-8-1, Appendix A, p. 115.
[251] Ibid., pp. 6–7.
[252] BCOAPO Final Argument, p. 25.
[253] Ibid.
[254] Ibid.
[255] FortisBC Reply Argument, p. 26.
[256] Ibid., p. 27.
[257] The CEC Final Argument, p. 27.

to have significant risk.[258] With respect to approvals, the CEC submits that the 'lack of assured approval' should not be equated with significant risk or that the utility will not be given its opportunity to earn a fair return.[259] Furthermore, the CEC notes that most utilities suffer from regulatory lag and submits that the "issues related to Indigenous communities and municipal challenges have been fully addressed in Indigenous Rights and Engagement and political risk and should not be re-reviewed in Regulatory Risk."[260]

In response to the CEC, FortisBC argues that utilities have lower overall returns (combined equity ratio and ROE) relative to the market; the rate regulator has discretion over setting the allowed ROE and other decisions that can have a material impact on the long-term success of the utility; short-term regulatory risk also arises from rates being set on a forecast basis; and FEI is subject to a number of other regulatory regimes, including Environmental Assessment processes, municipal requirements, and the requirements and processes of Indigenous communities.[261]

Panel Determination

Although the business risks presented by FEI are categorized, we consider business risks holistically since a utility is affected by the interplay between all its business risks, some of which may offset others.

Business risk evaluation is a matter that does not lend itself to a simple delineation of items into absolutely discrete categories. Nor does it lend itself to the application of an algorithm or equation in a purely mechanistic manner to calculate risk either overall or by category. Thus, the Panel accepts that there is inevitably some overlap between the business risk categories but does not consider this to be problematic.

The Panel accepts that FEI used the same risk categories as in the FEI 2016 COC proceeding thus facilitating comparisons over time. Additionally, the Panel considers it reasonable to expect that new business risk factors will emerge over time such as the Indigenous Rights and Engagement risk which has been promoted to its own risk category in this proceeding. Overall, the Panel considers that the categories of business risk and the risk factors are reasonable and appropriate, however are not all equal, for the purposes of evaluating overall changes in business risk for FEI.

The Panel notes costs associated with certain risk categories such as commodity prices and Indigenous engagement activities will largely be borne by ratepayers since increases in operating costs and capital projects are generally recoverable through rates. In contrast, some elements of Energy Transition risk pose an existential risk to FEI's shareholders and impact the risk of stranded assets which increases the risk that shareholders will not be able to earn their full return. Therefore, the Panel will not consider changes in ratepayer risks in isolation as changes to FEI's overall business risk.

In order to assess the extent of the impact of changes in business risks on shareholders' expected return, the Panel needs to consider investors' perceptions of business risks in addition to the real business risks that have emerged in the last few years. A cumulation of perceived ratepayer risks could shift the risk to the shareholder if

[258] The CEC Final Argument, pp. 27–26.
[259] Ibid., pp. 25–26.
[260] The CEC Final Argument, p. 25.
[261] FortisBC Reply Argument, pp.27–28.

the utility is no longer viewed as an attractive investment. Both experts, Mr. Coyne and Dr. Lesser, agree that if perceived risks are commonly believed, they will be relevant to the calculation of expected returns.

The Panel will not review all of the submissions made by FEI and interveners on the various business risk categories. Instead, we will focus on how FEI's various business risk categories have changed since 2016 from a shareholder and investor perspective. Thus, we have not focused on business profile and energy supply risk categories, as we agree that both are similar to 2016 and no parties raised an issue with FEI's assessment. We note that changes in business risks for an investor must also be considered, in part, relative to comparable entities, not just against itself at a previous point in time. Therefore, we will focus on those areas where FEI has noted changes in risk and discuss whether we agree with FEI's assessment of those changes and whether they increase risk, real or perceived, to the shareholder and investor as opposed to the ratepayer. We begin our analysis with an assessment of FEI's economic conditions risk below.

Economic Conditions

FEI submits that the economic condition risk has increased largely due to inflation increases caused by the current economic environment. The Panel notes that FEI has not provided price-elasticity evidence that demonstrates inflationary pressures on rates have caused, or will cause, a reduction in consumption. Evidence presented indicates that energy customer retention is influenced by the worsening perception of natural gas but not by increases in inflation. Additionally, the Panel notes that FEI is continuing to forecast customer additions in the prevailing economic conditions.

The Panel acknowledges that economic conditions are different than in 2016; however, we are not convinced that this risk results in any increased real risk to the shareholder or investor as FEI's O&M expenditures, and its growth capital are currently indexed to a composite inflation factor under its multi-year rate plan and are recoverable from ratepayers. If this mechanism wasn't effective, the Panel expects that FEI would make an application to the BCUC to correct it.

Similarly, while there may be a higher risk of the economy worsening, the Panel is not persuaded that this will result in investors perceiving FEI or any utility stocks to be less attractive as a result. As noted by FortisBC, utility stocks are characterized as defensive and investors holding utility stocks expect earnings to remain stable and grow slowly in most economic conditions. Therefore, the Panel disagrees with FortisBC's assessment that the economic conditions pose a higher risk to FEI's shareholder and investors than in 2016, as this is a risk borne by the ratepayer. Accordingly, **the Panel finds that the economic conditions risk for FEI's shareholder and investor is similar to what it was in 2016.**

Political

FortisBC notes that the Energy Transition risk is apparent in the BC government's recently updated Roadmap which is anticipated to have a significant impact on FEI's competitive and operational landscape, resulting in FEI to assess its political risk as significantly higher than 2016. The evidence shows that the Energy Transition represents a fundamental change that has a pervasive impact on FEI's business and that the change in BC is markedly different than in other jurisdictions as a result of government policies relating to climate change, decarbonization and electrification that have emerged since 2016. The Panel considers this to be the biggest driver of real and perceived risk for FEI's shareholder primarily as a result of all levels of government addressing climate change concerns and the uncertainty regarding the role that BC's natural gas utilities will play in addressing climate change concerns, especially when compared to utilities operating in other jurisdictions since the FEI 2016 COC proceeding.

The Panel agrees with BCOAPO that "the critical aspect regarding Political risk is the uncertainty regarding future policies and the impact they will have on FEI's business" [262] and agrees with the CEC that there is a growing bias against the use of natural gas on the part of multiple policymakers. Accordingly, **the Panel finds that the political risks faced by FEI's shareholders have increased significantly since 2016.**

Indigenous Rights and Engagement

FEI assesses its business risk related to relationships with Indigenous groups in BC as higher relative to the time of the FEI 2016 COC proceeding. The Panel acknowledges there are uncertainties and unknowns, as FEI's operations are subject to land claims due to the lack of treaties in BC compared to other parts of Canada which add to the perceived risks for FEI's investors. This uncertainty is greater for FEI relative to other utilities in North America, but the Panel finds it hard to determine the precise magnitude of that difference and how it might change in the future. The Panel also notes that while project approvals for FEI are potentially impacted due to concerns in this area, the costs associated with these impacts are largely a ratepayer risk, as they are recoverable through rates.

BCOAPO agrees with FortisBC that FEI's risk is higher from 2016 but notes that FEI is not involved in any litigation initiated by Indigenous groups. The Panel is not persuaded by BCOAPO's comments. While FEI may not be involved in Indigenous litigation now or in the past, this does not diminish investors' perception that this risk exists, especially operating on unceded land. The CEC submits that Indigenous risk should be considered less risky than that in 2016, as it is largely mitigatable. The Panel disagrees. Rather, we agree with FortisBC that its commitment to developing meaningful relationships with Indigenous communities cannot fully mitigate investors' perception of Indigenous risks. Therefore, while this risk is largely borne by ratepayers, there is perceived risk by investors that could affect FEI's shareholders. As a result, **the Panel finds that the Indigenous Rights and Engagement risk to FEI's shareholders and investors is higher than it was in 2016.**

Energy Price

FEI's assessment is that the overall real energy price risk is higher than 2016 partially due to volatility in natural gas prices. While the Panel accepts that current natural gas prices are more volatile than in 2016 due to increased weather events, forecast LNG demand growth, and forecasted decreases in oil production, this increase in real energy price risk will be largely borne by the customer through rates. The Panel does note, however, that while natural gas prices are still lower than other forms of energy, as government policies encourage decarbonization by offering subsidies and tax incentives for electric appliances, natural gas' relative price advantage over electricity may not be maintained, thereby increasing perceived risk among investors. BCOAPO agrees with FortisBC except it submits that forecast natural gas commodity prices are in line with those in 2016. The Panel is not convinced that Commodity Price risk being similar to 2016 would offset the increased risk associated with price volatility, but nevertheless the associated costs would be recovered from ratepayers through FEI's rates. The CEC considers energy price similar to 2016, as it submits that adding renewable natural

[262] BCOAPO Final Argument, p. 15.

gas supply to the portfolio should be treated as a mitigating factor with respect to the effects of the Energy Transition and will likely serve to mitigate the political, regulatory and customer risk.

The Panel agrees with FortisBC that as FEI blends higher-cost renewable gas into its portfolio, this will likely serve to put pressure on its price advantage relative to other forms of energy, thereby increasing investors' perception of energy price risk. Therefore, while energy price risk is largely borne by ratepayers, it is reasonable that investors' perception of risk will increase if the relative natural gas price advantage may not be maintained, and this could affect investors' expected return. Accordingly, **the Panel finds that FEI's energy price risk to the shareholder and investor is higher than it was in 2016.**

Demand/Market

FortisBC lists several contributors to the increase in demand/market risk, including the worsening of BC residents' perception of natural gas and the development of new technologies, like electric heat pumps, that aim to shift demand away from natural gas. The Panel accepts that BC residents' energy choices are increasingly influenced by a desire to use energy efficiently, to adopt lower carbon and renewable energy sources, and to generally reduce the negative impacts of climate change leading to a reduction in the end-use market share for natural gas and resulting in an increase in perceived risk by investors and a real risk for shareholders as compared to 2016. The Panel also agrees this is anticipated to result in a future reduction of new customer capture rates and perhaps even attrition of existing customers. Fewer customers to cover costs may result in an increase in natural gas delivery rates for remaining customers.

BCOAPO states that FortisBC's assessment of FEI's demand risk is overstated and points out that increases in non-residential sectors' UPC have more than offset any trend in the lower residential sector UPC. The Panel is not persuaded by BCOAPO's argument, as we find the increased risk in this category to be driven by factors leading to a reduction in the market share for natural gas. However, we find that FEI's customers bear some of this risk, especially those customers that lack the financial means to convert their residences to alternative heating sources to mitigate increasing natural gas costs**.**

The CEC states that the Panel should find there to be similar risk as in 2016 based on the FEI LTGRP proceeding evidence and that declining market share does not necessarily represent declining revenues or an inability for the utility to achieve its ROE. Although the Panel agrees to an extent, we consider that declining market share would be perceived negatively by investors thereby affecting the shareholder's expected returns. Accordingly, **the Panel finds that FEI's demand/market perceived risk for the shareholder and investor to be higher than it was in 2016.**

Operating

FEI submits that, compared to the FEI 2016 COC proceeding, its operating risk has increased. While FEI states that negative attitudes toward the fossil-fuel industry may hinder FEI's ability to recruit workers, complete approved projects, and meet environmental and safety requirements or obtain necessary approvals and permits, no evidence has been provided to indicate this risk is higher than in 2016 or is perceived by potential investors as higher compared to other gas utilities.

The Panel accepts that permitting requirements are changing, which may lead to higher costs related to FEI's ongoing operating and maintenance activities and its larger construction projects. However, FEI did not present evidence that these changing requirements have resulted in expenditures for which it has not received approval to recover from its customers.

FEI also submits that other unexpected events, such as more frequent extreme weather events and increased incidences of cyberattacks, can impact its ability to maintain and operate its system, thereby increasing operating risk. The Panel agrees with FEI that it is not necessary to demonstrate that each risk factor will impede FEI's ability to achieve its ROE. Rather it is incumbent upon FEI to demonstrate that investors perceive a long-term risk of its ability to recover investments. FEI did not present evidence that demonstrates that investors view these risks as being greater for FEI than for other utilities, nor did FEI provide evidence demonstrating that it has been unable to recover its incurred expenditures needed to address these operating risks. Based on the foregoing, the Panel is not persuaded that FEI's overall operating risk has increased for its shareholder since 2016. **The Panel finds that FEI's operating risk is similar to what it was in 2016**.

Regulatory

FEI argues that its overall regulatory risk is higher than what was assessed in the FEI 2016 COC proceeding. FEI submits that regulatory uncertainty gives rise to the risk that the allowed return or rates may not meet the Fair Return Standard, or that necessary investments are not approved. However, FEI provides no evidence that regulatory uncertainty has led to an increase of perceived risk from investors or rates being set at a level that does not provide FEI an opportunity to earn its allowed return. The Panel agrees with the CEC that "the 'lack of assured approval' should not be equated with significant risk."

FEI submits that risk associated with regulatory lag and ultimate approval of cost recovery has also increased since 2016 when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. While the Panel accepts that these requirements have become more onerous since 2016, FEI provides no evidence that these changing requirements have resulted in expenditures for which FEI has not received approval to recover from its customers nor is this risk perceived by investors to be higher for FEI than for other utilities.

With respect to FEI's submission that the BCUC's decision to consider that a more generic approach to deferral account financing treatment results in increased regulatory risk, no decision has yet been reached. The Panel agrees with BCOAPO that FEI (and FBC) will have a full opportunity to present their views in an open and transparent proceeding before the BCUC before any decision is made. Therefore, the Panel is not persuaded that FEI's overall regulatory risk has increased for its shareholder since 2016. **The Panel finds that FEI's regulatory risk is similar to what it was in 2016.**

Overall Business Risk

Interveners generally agree with FEI that its overall business risk has increased, but to a lesser degree than submitted by FEI. The CEC submits that FEI has a key risk in the Energy Transition, but that many of the other risks are overstated,[263] and recommends that the BCUC find FEI's business risk to be slightly higher than in

[263] The CEC Final Argument, p. 9.

2016.[264] RCIA submits that the perception of FEI risk appears to be higher today than it was in 2016, but states that FEI exaggerates the magnitude of such differences.[265] RCIA submits that given the absence of clear, objective evidence validating an absolute increase in business risk, RCIA opposes increasing FEI's equity thickness to the level requested by FEI.[266] BCOAPO agrees that FEI's business risk has increased since the FEI 2016 COC proceeding; however, it does not view FEI's business risk as having increased to the degree suggested by FEI.[267]

Given the findings discussed above associated with the changes in FEI's business risks to the shareholder, **the Panel finds that FEI's overall business risk has increased since 2016.** That increase is most significantly attributable to the increase in political risks associated with the Energy Transition and the cumulative effect of the perceived risks in Indigenous Rights and Engagement, energy price, and demand/market risks that could shift the risk to the shareholder if the utility is no longer viewed as an attractive investment by investors.

The Panel will address the impact of the increased business risk on FEI's capital structure and ROE, which are also influenced by factors beyond business risk, in Section 6.3 below (Overall Capital Structure and ROE).

4.3 FBC Business Risk

Unlike FEI, FBC's business risk was last assessed in the BCUC 2013 GCOC - Stage 2 proceeding.[268] In FortisBC's evidence, FBC provides an overview of its business risks across nine categories: four of which it considers to be of similar risk-level since 2013, with four categories considered to be of higher risk and only one considered to be lower.

FBC used similar categories as in the 2013 GCOC proceeding, other than the Indigenous Rights and Engagement risk factor. It was previously subsumed under political risk but has now been promoted to its own risk category. Additionally, the operating risk category has new risk factors: Project Resistance and Cybersecurity.[269] FBC summarizes its risk in the GCOC proceeding as "being similar to what was assessed in the 2013 Proceeding."[270] FortisBC prepared Table 10 below summarizing this risk assessment.

264 The CEC Final Argument, p. 28.
265 RCIA Final Argument, p. 31.
266 RCIA Final Argument, p. 31
267 BCOAPO Final Argument, p. 25
268 Exhibit B1-8, p. 2
269 Exhibit B1-8-1, Appendix B, p. 1.
270 Ibid.

Table 10: Summary of FBC's Business Risk[271]

Business Risk Category	Risk Factor	Change in Risk Since 2013
Business Profile		**Similar**
	Type and Size of the Utility	Similar
	Service area	Similar
	Customer profile	Higher
Economic Conditions		**Higher**
	Overall economic conditions	Higher
Political		**Lower**
	Energy policies and legislation	Lower
Indigenous Rights and Engagement		**Higher**
	Legislative and policy developments	Higher
	Aboriginal rights and title	Higher
	Social license/work interruption	Higher

Business Risk Category	Risk Factor	Change in Risk Since 2013
Energy Price		**Similar**
	Power supply cost	Higher
	Competition with electricity	Higher
	Competition with natural gas	Lower
Demand/Market		**Similar**
	New technologies	Similar
	Wholesale and Industrial load	Similar
	Use per customer	Similar
	End-use market share	Lower
Energy Supply		**Similar**
	Security and reliability of supply	Similar
Operating		**Higher**
	Infrastructure integrity	Similar
	Unexpected events	Higher
	Project resistance	New (Higher)
	Cybersecurity	New (Higher)
Regulatory		**Higher**
	Regulatory uncertainty and lag	Higher
	Administrative penalties	Similar

Similar to FEI's business risk assessment above, the sections below review each business risk category and the positions of parties. To provide a comprehensive discussion, the Panel addresses parties' submissions and then provides overall findings and determinations on changes to FBC's business risks since the 2013 GCOC proceeding.

<u>Business Profile</u>

FortisBC states that FBC's structure as a fully integrated electric utility contributes to a higher risk profile than that of a distribution-only utility of a similar size - a situation exacerbated by a less diverse and relatively small customer base, concentrated in a small, but geographically diverse service area. Twenty-five percent of FBC's revenue and more than 30 percent of load are attributable to two customer classes, Industrial and Wholesale, a significant number of which can receive service from alternate sources of supply with only limited notice.

[271] Exhibit B1-8-1, Appendix B, p. 2–3.

Despite the slight increase in FBC's customer profile risk due to a higher share of the industrial sector being concentrated in forestry and cryptocurrency mining for the company's load and revenue profile, FBC has assessed its overall business profile risk to be similar to what was assessed in the 2013 GCOC proceeding.[272] FortisBC also acknowledges the Government/Education/Health sector has grown from 15 percent of the load in the top 20 customers in 2013 to 20 percent in 2020.[273]

Positions of Parties

BCOAPO submits the make-up of the revenue contribution from FBC's top industrial customers has changed and shifted from the more volatile forestry and technology sectors to the more stable Government/Health/Education sector. Overall, BCOAPO questions whether the risk associated with FBC's customer profile has materially increased (if at all) since 2013 and submits that FBC's business risk is similar to that in 2013.[274]

The CEC submits that it does not find the addition of a cryptocurrency customer to be an added risk but should instead be viewed as further diversification with the benefit of additional load. The CEC recommends that the BCUC find that the business profile risk is similar, or potentially lower than that from the 2013 GCOC proceeding due to the effects of the Energy Transition.[275]

In reply to the CEC, FBC states that there is ample evidence that the addition of the cryptocurrency customer raises the overall risk profile of FBC's Industrial load.[276]

ICG submits that there has been no increase in business risk so there should be no increase to the equity ratio.[277]

Similarly, RCIA submits that there is a lack of clear, objective evidence validating an increase in FBC's business risk.[278]

Economic Conditions

FortisBC states that economic conditions can affect the ability of utilities to attach new customers or retain existing customers and maintain throughput levels, in addition to affecting utility access to capital and cash flow from customers. FortisBC assesses that the record-high inflation rate, caused by government fiscal and monetary policy, and BC's challenges for long-term economic growth, point to higher risk. However, FortisBC states that economic conditions pose an elevated level of risk to smaller utilities because the smaller utilities have fewer abilities to diversify their operations and protect themselves against economic-driven volatility.[279]

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[272] Exhibit B1-8-1, Appendix B, p. 3, Exhibit B1-8, p. 19.
[273] Exhibit B1-9, BCUC IR 33.9.
[274] BCOAPO Final Argument, pp. 29, 36.
[275] The CEC Final Argument p. 30.
[276] FortisBC Reply Argument, pp. 31–32.
[277] ICG Final Argument, p. 16.
[278] RCIA Final Argument, p. 31.
[279] Exhibit B1-8-1, Appendix 8, p. 13.

Positions of Parties

BCOAPO agrees that there is both greater uncertainties associated with the economic outlook for BC (and Canada), particularly in the short-term, and lower prospects for longer term growth.[280] However, the CEC submits that the overall economic conditions affecting the globe should be considered to be undiversifiable risks and should be provided with little to no weight in the BCUC's determinations regarding corporate risk.[281]

In reply to the CEC, FBC states that it is axiomatic that economic conditions can bring different risk to different enterprises and part of the focus of this proceeding is the effect of changed economic conditions on cost of capital for utilities.[282]

Political

FortisBC defines political risk as the potential for governments or other stakeholders to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations relating to such issues as tax, energy and environmental policies, industry structure, and safety regulations.[283] FortisBC states that the government push for electrification of the BC economy as the preferred option to reduce emissions is providing FBC with both opportunities and challenges. Namely, government policies to electrify the building and transportation sectors can increase FBC’s market share and load; however, rapid policy-driven customer migration from fossil fuels to electricity presents operational challenges for FBC which has limited resources in a small geographical service territory.[284]

Therefore, FortisBC states that over-reliance of government policy on electrification as the only solution to the climate change crisis can lead to increased costs to FBC and its customers.[285] In addition, FortisBC states that the government’s ability to subsidize BC Hydro customers is not a path open to FBC. BC Hydro is the primary beneficiary from FEI's challenges in the Energy Transition.[286] Overall, however, FBC assesses that its political risk is lower than what was assessed in the 2013 GCOC proceeding.[287]

Positions of Parties

BCOAPO and the CEC submit that FBC's political risk is lower now than in 2013 due to the Energy Transition and the associated policies that favour electrification.[288] However, the CEC disagrees that BC Hydro is the 'Primary Beneficiary of Fuel Switching' from FEI, as FBC is generally not in competition with BC Hydro. The CEC finds it incongruent that FortisBC is concluding that rapid growth presents risk while also stating that the lack of growth potential due to limited area size is a risk and recommends that little weight be assigned to these arguments.[289]

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280 BCOAPO Final Argument, p. 14, 29.
281 The CEC Final Argument, p. 31.
282 FortisBC Reply Argument, p. 32.
283 Exhibit B1-8-1, Appendix B, p. 14.
284 Exhibit B1-8, p. 18.
285 Exhibit B1-8-1, Appendix B, pp. 14–15.
286 Exhibit B1-8, p. 18; Transcript Volume 5A, p. 706.
287 Exhibit B1-8, p. 18.
288 BCOAPO Final Argument, p. 29, The CEC Final Argument, pp. 30–31.
289 The CEC Final Argument, p. 31.

ICG states that the Energy Transition that limits the future growth prospects of FEI is mirrored in expanded FBC growth prospects. That is, the fundamental changes that are occurring in the energy sector for FEI are mirrored in fundamental changes to the business risks of FBC.[290]

In reply to the CEC, FortisBC states that FBC points out the following: (i) that BC Hydro is the primary beneficiary of fuel switching from FEI, to place the impact of fuel switching policy in its proper context, as BC Hydro has greater overlap between its service territory with that of FEI; (ii) municipal fuel switching policy is mostly being implemented in BC Hydro's service territory rather than FBC's; and (iii) heat pumps are more competitive in the Lower Mainland and Vancouver Island than in FBC's service territory. FortisBC also submits that the CEC's political risk argument overlooks how rapid growth from the Energy Transition could present risk; FBC has limited opportunity to expand its service territory, as it is surrounded by BC Hydro territory and growth in FBC's customer base and accelerated electrification in its existing service area could pose threats to grid integrity.[291]

In reply to ICG, FortisBC notes that ICG appears to base its position on the incorrect proposition that FBC's business risk and FEI's business risk is a zero-sum game. FortisBC submits that business risk is not limited to a consideration of the give-and-take growth prospects of natural gas versus electric utilities. FortisBC states that FBC faces higher risk in some areas and accelerated growth comes with its own set of risks to FBC.[292]

Indigenous Rights and Engagement

FBC defines the Indigenous Rights and Engagement risk as the potential for governments to negatively impact utility operations through policy, legislation and/or regulations concerning Aboriginal rights and title or by Indigenous groups intervening directly in the utility regulatory process or by asserting Aboriginal rights and title. FBC faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of the BCUC's 2013 GCOC proceeding. This elevated risk is based on the evolving nature of the Crown's relationship with Indigenous groups, developments in reconciliation in Canada, significantly increased expectations among Indigenous groups, and legal claims related to Aboriginal rights and title.[293]

Positions of Parties

BCOAPO submits that, while Indigenous Rights and Engagement risk has increased since 2013, FBC appears to be effectively managing the risk such that it has not impacted/will not impact FBC's business to the extent suggested by FBC's evidence.[294]

The CEC submits that the risk in this category is significantly lower than that for FEI in that FBC's land area is confined and there are fewer Indigenous groups affected by FBC operations. The CEC submits that the risk to FBC related to Indigenous Rights and Engagement is largely the same as it was in 2013. The CEC recommends that the BCUC find FBC's Indigenous Rights and Engagement risk to be similar as in the 2013 GCOC proceeding.[295]

[290] ICG Final Argument, p. 4.
[291] FortisBC Reply Argument, pp. 32–33.
[292] FortisBC Reply Argument, p. 31.
[293] Exhibit B1-8-1, Appendix B, p. 16.
[294] BCOAPO Final Argument, p. 30.
[295] The CEC Final Argument, p. 32.

In reply to the CEC, FortisBC submits that FBC's Indigenous rights and engagement risk must be viewed considering its small size — the fact that FBC's service territory engages with fewer Indigenous traditional territories than FEI does not work to lower FBC's risk. The potential impacts of FBC's operations on Indigenous communities are no less meaningful because its operations have the potential to affect fewer Indigenous groups.[296]

Energy Price

FortisBC states that the analysis of energy price risk focuses on power supply factors placing upward pressure on FBC's rates and on the competitiveness of FBC's rates. While the risks related to the BC Hydro Power Purchase Agreement rate increases remain similar to 2013, FortisBC notes that market price volatility and purchase agreements contract rate risk have increased.[297] The level of utility rates can influence consumers' energy choices. Specifically, higher electricity rates in FBC's service territory can hinder FBC's ability to attract new customers (particularly new industrial and larger commercial customers). In addition, higher electricity rates can discourage residential customers from using electricity for space heating and water heating which can affect FBC's market share and UPC.[298]

While FortisBC acknowledges that FBC's rate competitiveness risk compared to BC Hydro is similar to what it was in 2013, FortisBC states it is trending higher. In addition, FBC's rate competitiveness relative to natural gas is similar to that in 2013; however, given expected increases to gas and carbon tax rates, FBC expects its rate competitiveness to improve.[299]

Positions of Parties

BCOAPO submits that the price risk is not as great as suggested by FBC but accepts FBC's overall assessment that its overall price/rate competitiveness risk is similar to that assessed in the 2013 GCOC proceeding.[300] The CEC recommends that the BCUC find the energy price risk to be similar to its finding in the 2013 GCOC proceeding and potentially lowering as new technologies continue to provide benefits.[301] ICG submits that power supply costs may have increased, but have not increased FBC's business risks, as the number of customers that can choose between BC Hydro and FBC is not material and is limited to a very small geographical area, and for that reason, competition with electricity should not be considered a significant risk.[302]

In reply, FortisBC only acknowledges that BCOAPO agrees and, in response to the CEC, submits that new technologies, like wind and solar energy generation resources, do not provide reliable capacity and as such, declines in the cost of the energy produce simply shifting the risk to capacity. The benefits of policies favouring electricity are offset at present by other factors.[303] FortisBC does not address ICG's submissions in its reply argument.

[296] FortisBC Reply Argument, pp. 33–34.
[297] Exhibit B1-8, p.18.
[298] Exhibit B1-8-1, Appendix B, p. 17.
[299] Exhibit B1-8, p. 19.
[300] BCOAPO Final Argument, pp. 30–31.
[301] The CEC Final Argument, p. 33.
[302] ICG Final Argument, pp. 5–6.
[303] FortisBC Reply Argument, p. 34.

Demand/Market

Demand risk, also referred to as market risk, generally refers to the risk arising from changes in consumer behaviour and the markets to which the utility has exposure.[304] FortisBC states that emerging technologies can provide challenges for FBC, as alternative sources of energy such as home solar generation can reduce the demand, while conversely new load requirements such as electric vehicle (EV) charging can increase the load requirements of FBC.

Both situations create risks for higher costs, as well as risks to grid integrity, including managing the timing of load on the system to avoid peak demand impacts. FortisBC also states that FBC continues to face demand risk in its wholesale and industrial customer segments because these customers are able to take service from competing utilities within the province, build generation to serve some or all of their load, or purchase electricity from the open market.[305] However, FortisBC states that no wholesale or industrial customers have left FBC, nor have they expressed an intent to leave FBC.[306]

In addition, FortisBC states that both building generation and arranging for third-party supply can be complicated and retail access to the open market for electricity purchases is not available.[307] Finally, FortisBC states that compared to 2013, FBC's residential and commercial UPC values have been on a downward trajectory while Industrial UPC has increased.[308] However, FBC has not included EV load growth in the declining residential UPC.[309] FBC expects an increase in its electricity thermal market share relative to natural gas and other fuel sources over the longer term as heat pump penetration increases, thereby reducing this aspect of FBC's market share risk from 2013 and current levels. Overall, FBC views its demand risk as similar to what was assessed in the 2013 GCOC proceeding.[310]

Positions of Parties

BCOAPO submits that there is limited risk to FBC of losing load from either wholesale or industrial customers seeking service from an alternative supplier or self generation. Also, BCOAPO notes that FBC has not taken the longer-term impact of EV load and heat pump penetration increases on the Residential UPC into account in its risk assessment. Finally, BCOAPO notes that the discussion of FBC's demand/market risk does not make any specific reference to the favourable trend of customers' energy choices trending towards more environmental and affordable sources of supply which will favor electricity. Overall, BCOAPO submits that the demand/market risk faced by FBC has likely decreased as compared to that in 2013.[311]

The CEC submits that there are always negatives and positives to be found with every type of change, and they should not be provided with weight unless they are likely to have a material impact. The CEC submits that in this case, the ability to meet peak load can reasonably be expected to be met with new infrastructure or demand

[304] Exhibit B1-8-1, Appendix B, p. 25.
[305] Exhibit B1-8, p. 19.
[306] Exhibit B1-9, BCUC IR 32.1.
[307] Ibid., BCUC IRs 32.1, 33.4.
[308] Exhibit B1-8, p. 19.
[309] Exhibit B1-10, BCOAPO IR 15.3.1.
[310] Exhibit B1-8, p. 19.
[311] BCOAPO Final Argument, p. 32.

side management as approved by the BCUC. The CEC recommends that the BCUC find the demand/market risk for FBC to be lower overall.[312]

In reply to BCOAPO and the CEC, FortisBC submits that FBC's overall demand/market risk is similar to what it was during the 2013 GCOC proceeding and stands by its final submissions.[313]

Energy Supply

FortisBC states, as in 2013, FBC's power supply comes from three sources:

i. Its own hydro generating plants - FortisBC describes the failure of a plant generating unit would result in the need to acquire replacement power, which may not be available due to either lack of available supply or available transmission, or may only be available on the open market at a significantly increased cost;

ii. Long-term contracts with suppliers - As long-term supply contract agreements expire, FBC states that there is no guarantee that it will be able to renew them, or that they could be renewed at a similar cost; and

iii. The wholesale market - FBC's dependence on the availability of third-party transmission capacity to meet demand increases the risk that FBC is not able to access cost-effective market supply.

FortisBC states that there is risk associated with each supply, but the level of risk remains similar to that in 2013.[314]

Positions of Parties

BCOAPO has no issues with FBC's assessment of its energy supply risk and the CEC agrees that the energy supply risk remains similar to that in the 2013 GCOC proceeding. However, the CEC recommends that the BCUC provide moderate weight to this category.[315]

FBC did not comment in its reply argument on the energy supply risk.

Operating

FortisBC states that operating risk is defined as the physical risks to the utility system arising from technical and operational factors, including asset concentration, the technologies employed to deliver service, service area geography, human error, and weather.[316] FortisBC explains that the primary operating risks associated with FBC's generation and infrastructure assets are related to the age and cost to maintain and upgrade these assets. FBC is exposed to additional risk from its transmission and distribution assets which are primarily above ground and the potential for increases in unpredictable extreme weather events, such as wildfires and flooding, to compromise the integrity of these assets.

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[312] The CEC Final Argument, p. 33.
[313] FortisBC Reply Argument, p. 34.
[314] Exhibit B-8-1, Appendix B, pp. 41–42.
[315] BCOAPO Final Argument, p.34, The CEC Final Argument, p. 34.
[316] Exhibit B1-8-1, Appendix B, p. 43.

Other unexpected events, such as the COVID-19 pandemic, disrupt supply chains and cause delays in FBC's capital work, which impacts its ability to maintain and operate its system. Additionally, FBC has experienced an increase in incidences of cyberattacks and expects to see increased resistance to projects, which will lead to higher risks to execute projects on time at the lowest reasonable cost. Therefore, FBC assesses its operating risk as being higher than in 2013.[317]

Positions of Parties

BCOAPO accepts FBC's assessment that its operating risk has increased since 2013 based on the factors cited by FBC.[318] However, the CEC recommends that the BCUC find the operating risk to be similar to that in 2013.[319] The CEC does not consider the age and cost to maintain the generation infrastructure assets as a higher risk for FortisBC and considers it at least the same as, or lower than previously, as ratepayers pay for necessary upgrades. The CEC submits that there may be some degree of selection or framing bias as FBC does not address distribution or other infrastructure except with respect to 'Unexpected Events'. While the CEC agrees that there is an increase in unexpected events, such as extreme weather affecting transmission and distribution, the CEC notes that FBC has additional advanced metering infrastructure embedded in its network which can assist with mitigating risk to customers.

Regarding project resistance, the CEC submits that the utility has the obligation, and the capability, to plan for and seek approval for appropriate timing and costing so that it can continue to execute projects cost effectively and on time and recommends that little to no weight be assigned to FBC's arguments. The CEC submits that cyberattacks are on the rise generally and should be considered as a non-diversifiable risk.[320]

In reply, FortisBC states that FBC's risk assessment is post-mitigation, and while risks such as cybersecurity may broadly impact other entities, the risk is more acute for utilities than many other enterprises. The increased threat of cybersecurity attacks may have serious repercussions. In addition, FortisBC also notes that it has provided ample evidence of serious and increasingly frequent extreme weather events, which cause lengthy outage periods for customers and require resource-intensive transmission and distribution infrastructure rebuilds. FortisBC submits that the potential costs associated with these increasing risks may prevent FBC from earning its allowed return. [321]

<u>Regulatory</u>

FortisBC defines regulatory risk as the degree to which FBC, as a regulated public utility, is dependent on regulators for timely and objective approvals that directly impact its ability to earn a fair return on and of capital. FortisBC has assessed FBC's overall regulatory risk as higher than what was assessed in the 2013 GCOC proceeding, with certain risk factors increasing and others being similar. FortisBC states that regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty which in itself gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are

[317] Exhibit B1-8, p. 20.
[318] BCOAPO Final Argument, p.34.
[319] The CEC Final Argument, p. 35.
[320] The CEC Final Argument, pp. 34–35.
[321] Fortis Reply Argument, p. 36.

set at a level that does not provide FBC with an opportunity to earn its fair return, or that necessary investments are not approved.

FortisBC states that there is uncertainty caused by the BCUC's decision to consider a more generic approach to deferral account financing treatment. FortisBC also notes that the risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2013 GCOC proceeding when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title.[322]

In addition, FortisBC states that the failure to comply with the adopted BC Mandatory Reliability Standards (MRS) requirements can lead to the BCUC imposing administrative penalties against FBC. Compared to 2013, the scope and comprehensiveness of the BC MRS requirements have increased. While FBC strives to comply with the BC MRS requirements, there is always a risk that non-compliance may occur.[323]

Positions of Parties

BCOAPO submits that MRS requirements do not give rise to an increase in regulatory risk relative to 2013, as FBC is familiar with the requirements. BCOAPO submits that FBC's regulatory risk remains relatively unchanged from that in the 2013 GCOC proceeding.[324]

In reply, FortisBC does not address BCOAPO's submission on MRS.

The CEC does not view FBC's additional concerns to be significant and notes that the BCUC can approve additional funding to cope with MRS requirements. Therefore, the CEC also applies its views on regulatory risk for FEI to FBC and recommends that the BCUC find FBC's regulatory environment to be favourable.[325]

In reply to the CEC, FortisBC does not address the CEC's submission on MRS and repeats the same arguments for FBC as it did for FEI.[326]

ICG submits that there is no evidence to support FBC's conclusion that regulatory uncertainty and lag have increased.[327] In reply to ICG, FortisBC states that it provided evidence of these business risks in its evidence, in numerous responses to information requests, and at the oral hearing. [328]

Panel Determination

Similar to its approach with the assessment of FEI's business risks, the Panel focuses on how FBC's business risk categories have changed since 2013 from a shareholder and investor perspective. Thus, we do not focus on business profile, energy price and supply risk categories, as we agree that all of these are similar to 2013 and no parties raised any material issue with that assessment. We address where FBC has noted changes in risk and

[322] Exhibit B1-8, p. 20.
[323] Exhibit B1-8-1, Appendix B, p. 55.
[324] BCOAPO Final Argument, p. 35.
[325] The CEC Final Argument, pp. 27, 35.
[326] FortisBC Reply Argument, pp.27–28, 37.
[327] ICG Final Argument, p. 5.
[328] FortisBC Reply Argument, p. 37.

discuss whether we agree with the changes and whether they affect the risk, real or perceived, to the shareholder and investor rather than to the ratepayer. We begin our analysis with an assessment of FBC's economic conditions risk below.

Economic Conditions

FBC assesses that its economic conditions risk is higher than in 2013 due to record-high inflation rates caused by government fiscal and monetary policy, and BC's challenges for long-term economic growth. The Panel notes that FBC did not provide evidence that this risk is perceived differently by investors for FBC than for other utilities. Additionally, the Panel finds no evidence to support FBC's submission that this risk will affect FBC's ability to access capital or impact its cash flow from customers, as increased cost resulting from inflations are recoverable from ratepayers.

The Panel is not persuaded that the present short-term economic conditions will materially affect the ability of FBC to attach new customers or retain existing customers and maintain throughput levels. As the costs are recoverable from ratepayers, and investors do not perceive this risk higher for FBC than a comparable utility, **the Panel finds that FBC's economic conditions risk to the shareholder and investor to be similar to what it was in 2013.**

Political

FBC assesses its political risk as lower than what was assessed in 2013 and the Panel agrees. The Panel notes that FBC, as well as BCOAPO, the CEC and ICG all submit that the risk is lower than in 2013. The Panel also notes that ICG submitted that "the Energy Transition that limits on the future growth prospects of FEI are mirrored in expanded FBC growth prospects".

The Panel agrees that business risk is not limited to a consideration of the give-and-take growth prospects of natural gas versus electric utilities. We accept that rapid growth from the Energy Transition presents opportunities for FBC, both real and perceived. However, it could also present risks that it will not be able to effectively deal with such rapid growth. The Panel puts more weight on growth opportunities because current policies and investor perceptions favour FBC as an electric utility and opportunities in most cases come with certain degree of risk. Therefore, on balance, **the Panel finds that FBC's political risk to the shareholder and investor is lower than it was in 2013.**

Indigenous Rights and Engagement

FBC assesses that it faces an elevated level of risk related to relationships with Indigenous groups in BC compared to 2013. We do not disagree but we find this risk is mitigated, at least in part, by the likely recovery of the costs associated with project delays and increased engagement from ratepayers through rates.
The Panel is persuaded that the potential and perceived impacts of FBC's operations on Indigenous communities are no less meaningful to those of FEI merely because its operations have the potential to affect fewer Indigenous groups.

In our view, while this risk is largely borne by ratepayers, this issue is likely to impact investors' perception of risk. However, as with many risks, the risks associated with Indigenous Engagement and Consultation also comes with opportunity to engage with First Nations and we encourage FBC to seek out those opportunities.

Accordingly, **the Panel finds that FBC's Indigenous Rights and Engagement risk to the shareholder is somewhat higher than it was in 2013**.

Demand/Market

FBC assesses its demand/market risk as similar to what was assessed in 2013. However, the Panel notes that BCOAPO and the CEC submit that demand/market risk is lower than it was in 2013. BCOAPO submits that FBC has not taken the longer-term impact of EV load and heat pump penetration increases on the Residential UPC into account in its risk assessment or makes any specific reference to its customer's energy choices trending towards those favouring electricity. The Panel considers that emerging technologies can also provide challenges for FBC, as alternative sources of energy such as home solar generation can reduce the demand on new load requirements, thereby offsetting some of the reduced risk associated with potential EV and heat pump load. The Panel also notes that any cost differences as a result of load will be absorbed by customers through rates.

Although the CEC submits that FBC's ability to meet peak load can reasonably be expected to be met with new infrastructure or demand side management as approved by the BCUC, the Panel considers this does not result in a reduction of demand/market risk for FBC, as the associated costs would have always been recoverable through rates. Further, the Panel agrees with the CEC that there are always negatives and positives with every type of change, and such changes should not be provided with weight unless they are likely to have a material impact or perceived to have an impact. In this case, the Panel finds that overall, the negative and positive impacts offset each other with minimal impact to the shareholder, in addition, there has been no indication that investors perceive this risk as lower than in previous years or less than another utility. Accordingly, **the Panel finds that FBC's demand/market risk to the shareholder is similar to what it was in 2013.**

Operating

FBC assesses its operating risk as being higher than in 2013. FBC submits that it is exposed to additional risk from the potential for increases in unpredictable extreme weather events such as wildfires and flooding which compromise the integrity of its transmission and distribution assets. BCOAPO agrees with FBC. The CEC, however, submits that this risk is similar to that of 2013. ICG submits that no weight should be given to this risk category in determining the appropriate capital structure for FBC, implying that the risk is similar to that of 2013.

FBC submits that the primary operating risks associated with FBC's generation and infrastructure assets are related to the age of these assets and their maintenance and upgrade costs. FBC also submits that other unexpected events, such as the COVID-19 pandemic, disrupt supply chains, cause delays in FBC's capital work, and impact its ability to maintain and operate its system. Similarly, FBC states that incidences of increased cyberattacks represent an increase to FBC's operating risk. The Panel notes that FBC did not present evidence that demonstrates that investors view these risks differently for FBC than for other utilities, nor did FBC provide evidence demonstrating that its ability to maintain and operate its system has been compromised, nor has it been unable to recover its incurred expenditures needed to address these operating risks. Accordingly, the Panel is not persuaded that FBC's operating risk has increased since 2013, and **the Panel finds that FBC's operating risk is similar to what it was in 2013.**

Regulatory

FBC assesses its overall regulatory risk as higher than what was assessed in 2013. FBC submits that risk has increased as a result of regulatory uncertainty, regulatory lag, and changing MRS requirements. BCOAPO, the CEC and ICG all submit that the risk is similar to what it was in 2013.

FBC submits that regulatory uncertainty gives rise to the risk that the allowed return or rates may not meet the Fair Return Standard, or that necessary investments are not approved. FBC provided no evidence that perceived regulatory uncertainty has led to its allowed return not meeting the Fair Return Standard, or rates being set at a level that does not provide FBC an opportunity to earn its allowed return. Similarly, FBC provided no evidence where recovery has been disallowed for approved investments. Finally, FBC provided no evidence that the likelihood of these outcomes occurring is higher today than in 2013, nor is the risk of these outcomes occurring or perceived to occur greater for FBC than it is for other utilities. Accordingly, the Panel is not persuaded that FBC's regulatory risk due to regulatory uncertainty has increased.

FBC submits that risk associated with regulatory lag and ultimate approval of cost recovery has also increased since the 2013 GCOC proceeding when considering increased requirements for stakeholder consultation, environmental reviews, and Indigenous rights and title. While the Panel accepts that these requirements have become more onerous since 2013, the Panel notes that FBC provided no evidence that these changing requirements have resulted in expenditures for which FBC has not received approval to recover the costs from its customers. Nor has FBC provided evidence that the likelihood of this occurring is higher today than in 2013, nor is the risk of this occurring or perceived to occur greater for FBC than it is for other utilities. Accordingly, the Panel is not persuaded that regulatory risk due to regulatory lag and ultimate cost recovery has increased.

FBC submits that the risk associated with MRS requirements has increased. FBC submits that MRS requirements have increased since 2013 and that there is always a risk that non-compliance with MRS may occur, which may lead to administrative penalties. The Panel accepts that MRS requirements have increased since 2013 and that non-compliance may lead to the imposition of administrative penalties. However, the Panel notes that the BCUC has not disallowed recovery of costs from customers associated with FBC meeting its MRS requirements, nor has FBC provided evidence that the likelihood of this occurring is higher today than in 2013, nor is the risk of this occurring or perceived to occur greater for FBC than it is for other utilities. Accordingly, the Panel is not persuaded that regulatory risk due to MRS requirements has increased. Thus**, the Panel finds the FBC's overall regulatory risk to the shareholder and investor to be similar to what it was in 2013.**

Overall Business Risk

While some of FBC's business risks have increased to a degree, these have been offset by reductions in other risk categories. The Panel notes that the CEC submits that overall, FBC's business risk is slightly lower than it was in 2013 due to the effects of the Energy Transition.[329] However, the CEC does not submit that this should result in a reduction to FBC's equity component. Other interveners submit that FBC's overall business risk is similar to that

[329] The CEC Final Argument, p. 30.

of 2013. RCIA submits that there is "… the absence of clear, objective evidence validating an absolute increase in business risk,"[330] and ICG submits that "[i]n the current circumstance of FBC, there has been no increase in business risk so there should be no increase to the equity ratio."[331] Finally, BCOAPO submits that "… the BCUC should conclude that, on an overall basis, FBC's business risk is similar to that of the 2013 GCOC proceeding";[332] however, BCOAPO also submits that FBC's business risk would be lower relative to that of other Canadian and US electric utilities[333].

Given the findings associated with each of the business risk categories, **the Panel finds that FBC's business risk overall has not changed materially since 2013.** This is attributable to most of the risk to the shareholder remaining similar to 2013 and the decrease in political risks associated with the Energy Transition compared to the perceived increase in risk for Indigenous Rights and Engagement, resulting in no net change in FBC's attractiveness as an investment to investors. The Panel will address the impact of this overall assessment of FBC's business risk on its capital structure and ROE, which are influenced by factors beyond business risk, in Section 6.3 below (Overall Capital Structure and ROE).

Having addressed the changes in business risks for FEI and FBC, we now review the various financial models used by the experts in assessing an appropriate ROE for the two utilities.

5.0 FINANCIAL MODELS

5.1 Rationale for the Use of Financial Models

Regulators rely on financial models because the cost of equity for a regulated utility cannot be observed. All models are simplifications of reality, using simplifying assumptions and as such, they are all subject to varying degrees of criticism.[334] Quantitative models produce a range of reasonable results from which the ROE is selected. Mr. Coyne states that the key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' forward-looking views of the financial markets in general and the subject company (in the context of the proxy group) in particular.[335]

Dr. Lesser explains that models that are used by regulators to set the cost of capital for regulated utilities should possess certain characteristics: 1) a sound basis in financial theory; 2) model transparency; and 3) minimal reliance on subjective factor. In addition, they shouldn't be systematically biased.[336]

Dr. Lesser further explains that methodologies used to estimate the allowed return on equity for a regulated utility should be consistent with accepted financial theory and basic economics, namely, that the allowed return reflects the opportunity cost of capital. Non-market approach, such as the Comparable Earnings approach is

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330 RCIA Final Argument, p. 31.
331 ICG Final Argument, p. 16.
332 BCOAPO Final Argument, p. 36.
333 Ibid.
334 Exhibit A2-3, p. 22.
335 Exhibit B1-8-1, Appendix C, p. 45.
336 Exhibit A2-3, p. 22.

unlikely to reflect the opportunity cost of capital, as it bases allowed returns on accounting measures which can be influenced by specific events or differences in accounting practices.[337]

Model transparency reflects two important dimensions: understandability and replicability and requires, in Dr. Lesser's view, the reliance on data that is publicly available or available at a low cost.[338] Finally, all models involve some degree of subjectivity owing to the choices of inputs but Dr. Lesser explains that subjectivity can be reduced to some extent when regulators specify the methodologies and the inputs that should be used to implement those methodologies beforehand. For example, adjusting model results to account for perceived anomalous capital market conditions without any underlying basis in financial theory and no empirical support is subjective. He recommends that regulators question these types of adjustments, as they can undermine confidence that the resulting allowed ROE values are 1) just and reasonable and 2) consistent with "reasonable decision-making".[339]

Mr. Coyne explains that no model can exactly pinpoint the correct return on equity, but rather each model brings its own perspective and set of inputs that inform the estimate of ROE and as such, no model should be relied upon individually without corroboration from other approaches. Mr. Coyne also notes that using multiple models mitigates the inherent imperfections in each of the models and there is additional value in using multiple models during "volatile market conditions, such as those experienced over the last decade." Furthermore, analysts must apply informed judgment to assess the reasonableness of results and to determine the appropriate weighting to apply to results under prevailing capital market conditions.[340]

In its 2016 Decision, the BCUC acknowledged the need to use multiple methodologies in determining a fair return on equity, stating:

> The Panel notes that while there are some differing perspectives among the experts and parties, their views are generally consistent with the Brattle Group Report's finding that decisions should be informed by use of multiple financial models and other indicators of investor expectations where appropriate. The Panel agrees it should consider the "totality of information resulting from applying multiple tests." The Panel also agrees it should consider all of the information from the application of the models presented, as well as other indicators of the fair ROE and should apply its own judgment to determine the appropriate ROE.[341]

Mr. Coyne presented the results of four models: multi-stage DCF, constant growth DCF, CAPM and Risk Premium. His recommendations ultimately reflect the average output of multi-stage DCF and CAPM models, which is the approach adopted in the 2016 Decision.[342] Mr. Coyne supports the BCUC's previous approach of using multiple methodologies and believes it is appropriate to place equal weight on the results of the CAPM and Multi-Stage DCF model. But he also notes that FERC includes the Risk Premium Model, in addition to the CAPM and Two-Stage DCF models, to establish the return for electric transmission companies, and gives equal weight to the results of those three approaches. Mr. Coyne further points out that in volatile market conditions, there is additional value in using multiple models. All models have their strengths and weaknesses, so relying on

[337] Exhibit A2-3, p. 23.
[338] Ibid.
[339] Ibid., pp. 24–25.
[340] Exhibit B1-8-1, Appendix C, pp. 45–46, Exhibit B1-9, BCUC IR 44.3.
[341] 2016 Decision, p. 47.
[342] FortisBC Final Argument, p. 136.

an equal weighting of two (or more) improves both the reliability of the estimate and the confidence that stakeholders can place in the results.[343]

FortisBC states that Mr. Coyne and Dr. Lesser agree on the importance of using multiple models to estimate a utility's cost of equity and submits that, ultimately, the BCUC should consider the result of all four models used by Mr. Coyne, even if greater weight is applied to the CAPM and Multi-Stage DCF results.[344]

As BCOAPO observes, the evidence is clear that, despite the numerous points upon which Mr. Coyne and Dr. Lesser disagree, they do both agree that ROE estimates should be based on the use of multiple models. BCOAPO supports this premise as a reasonable response to a challenging issue.[345]

The Panel will discuss its views of each model in the next sub-sections, reviewing in turn the CAPM, the DCF methodology, and the Risk Premium Model. The Panel will then determine the various weightings to be attributed to each model in Section 6.3.

Briefly, the CAPM is based on the long-observed relationship between non-diversifiable risk and expected return, the DCF methodology is based on the premise that today's stock price represents investors' expectations regarding future cash flows from holding that stock in terms of dividends and price appreciation, and the Risk Premium Model is based on the premise that common equity capital is riskier than debt and, therefore, equity investors require a greater return than would bondholders.

5.2 Capital Asset Pricing Model

The CAPM is commonly used in business valuation and regulatory jurisdictions to estimate ROE. The CAPM financial model estimates the expected return of an investment or security based on its riskiness relative to the rest of the market. The BCUC has recognized the use of the CAPM in prior cost of capital decisions.[346]

The CAPM is based on the relationship between the required return of a security and the systematic risk of that security and is defined by the following equation:

$$K_e = rf + \beta(rm - rf) \tag{1}$$

Where:

K_e = the required ROE for a given security;

rf = the risk-free rate of return;

β = Beta is the systematic risk of an individual security;

rm = the required return for the market as a whole; and

(rm – rf) = Market risk premium (MRP) is the premium that equity investors demand to compensate them for the extra risk they accept

[343] Exhibit B1-9, BCUC IR 44.3.
[344] FortisBC Final Argument, p. 136.
[345] BCOAPO Final Argument, p. 37.
[346] 2013 Decision, 2016 Decision.

Dr. Lesser states that the CAPM is the most used approach for estimating allowed ROE values. In his view, the model is understandable, transparent, based on sound financial theory, and there are readily available data with which to develop CAPM estimates. He explains that the assumptions used in deriving estimates for each of the three CAPM components can have a significant impact on the ROE result and that key empirical issues for regulators to consider when using the CAPM are as follows:

a) What risk-free rate (*rf*) should be used;

b) Whether to use raw or adjusted beta and to adjust for differences in leverage to reflect differences in capital structure;

c) How to determine the expected market return (*rm*) and whether the market-risk premium (*rm – rf*) should be historical or forward-looking;[347] and

d) Whether a size premium is appropriate.[348]

5.2.1 Risk-Free Rate

The risk-free rate of return is a theoretical return that carries no risk. Dr. Lesser points out that even though a truly “risk-free” asset does not exist, most regulators rely on long-term government bond yields as the risk-free rate when using the CAPM to set the allowed ROE because determining an allowed ROE is a long-term exercise and the yield on long-term government bonds is the closest thing to the hypothetical risk-free rate.[349]

Mr. Coyne and Dr. Lesser agree that the yield on long-term government bonds is the appropriate basis to estimate the risk-free rate of return. They also agree that using a 30-year horizon is appropriate.[350] However, one area of disagreement is Dr. Lesser’s use of current average government bond yields instead of Mr. Coyne’s use of forecast bond yields.[351]

Mr. Coyne states that since the bond yields in December 2021 remain near historical lows, adjustments are necessary to better reflect forward-looking circumstances because investors are factoring higher interest rates into their longer-term expectations and required returns. He relies on the 30-year forecast bond yields for his analysis, calculated as the 2022–2024 average *Consensus Economics* forecast of the Canadian 10-year government bond, later updated to 2023–2025, plus the average spread between 10-year and 30-year government debt. Mr. Coyne explains that the use of a forecast yield is appropriate, as it provides a forward-looking view of the cost of equity and accounts for the market’s expectations for a return to more normal (higher) interest rates.[352] Also, Mr. Coyne emphasizes that it is a longstanding regulatory practice in Canada to base the cost of capital on an expectation of the bond yield using some sort of forecast.[353]

Dr. Lesser prefers using current average government bond yields. In his view, based on the Efficient Market Hypothesis, the current yield already reflects investors’ collective expectations about interest rates such that using forecasts would amount to a double-counting of expectations. Also, he remarks that low interest rates

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[347] Exhibit A2-3, p. 58.
[348] Ibid., p. 59.
[349] Exhibit A2-3, p. 45.
[350] Exhibit B1-8-1, Appendix C, p. 56, Exhibit A2-3, p. 46.
[351] Exhibit B1-21, p. 5.
[352] Exhibit B1-8-1, Appendix C, p. 56.
[353] Transcript Volume 3, p. 184, Line 13–16.

induced by government actions do reflect the true cost of capital and argues that the opposite begs the question of what is the "true" cost of capital.[354]

Dr. Lesser relies on both the 30-day and 90-day average bond yield. Dr. Lesser states that he often will use a one-month average (30-days) because interest rates tend to be less volatile than stock prices.[355] However, he also notes that it would be reasonable to use a slightly longer period, between one and three months (i.e. 90 days).[356] Dr. Lesser notes that, while he supports using the current yield, the decision on the time period is subjective on the best way to approach it, stating that "it may make very little difference" and there is no "optimal averaging period".[357]

Mr. Coyne disagrees and reiterates that under current market circumstances (around June 2022), when interest rates are changing rapidly as central banks in the US and Canada normalize monetary policy in response to higher than expected inflation, the use of current average yield tends to understate the level of interest rates during the period for which the cost of equity is being set.[358] During the oral hearing, Mr. Coyne explained:

> MR. COYNE: But case in point going back to December when we put our data together, our forecast bond yield for the U.S. long term is 2.91 percent and for Canada it was 2.58 percent. In October [2022], the actual for Canada is 3.374 and the actual for October in the U.S. is 4.04. So those numbers are already over a percent higher than what we had predicted -- what Consensus Economics had predicted back then. They had the trend right, but not the magnitude right of just how much it was going to increase. Had I adopted Dr. Lesser's approach back in December of 2021, I would have used a Canadian bond yield of only 1.76 percent and a U.S. bond yield of 1.84 percent. And as I said, they're now 4 percent in the U.S. and 3.3 percent in Canada. So it clearly would have underestimated what's occurred in the market for government bond yields, even the forecast underestimated what's occurred.[359]

Reflecting the Panel's determination that it should be using the October 2022 data to inform the establishment of an appropriate ROE, the following table presents the October 2022 risk-free rates resulting from the two experts' respective approaches.

Table 11: Summary of Risk-Free Rates[360]

Canada			
As of	**Forecast**	**Current 30-day**	**Current 90-day**
October 2022	3.21%	3.27%	3.09%
U.S.			
As of	**Forecast**	**Current 30-day**	**Current 90-day**
October 2022	3.50%	3.92%	3.43%

[354] Exhibit A2-3, p. 46.
[355] Transcript Volume 3, p. 182, Lines 5–8.
[356] Ibid., p. 201, Lines 22–26 to p. 202, Lines 1–9.
[357] Ibid., p. 201, Lines 22–26 to p. 202, Lines 1–9.
[358] Exhibit B1-21, p. 14.
[359] Transcript Volume 3, p. 184, Lines 17–26 to p.185, Lines 1–8.
[360] Information in the table has been compiled from Exhibit B1-8-1-2, A.2 Gas and Electric attachments for Forecast (Canada and US), Exhibit B1-8-1-2, B.6 Gas and Electric attachments for Current 30-day (Canada and US), Exhibit B1-8-1-2, B.7 Gas and Electric attachments for Current 90-day (Canada and US).

FortisBC submits that the risk-free rate should be determined using forecast bond yields, not current government bond yields. FortisBC states that the BCUC should find that Mr. Coyne's approach is most reasonable since it best reflects how investors make decisions. FortisBC refers to Mr. Coyne's statement that the entire forecasting industry is predicated on investors using forecasts, rather than just the current price, in making investment decisions. FortisBC also points out that Mr. Coyne's approach is consistent with the logic underpinning automatic adjustment mechanisms (AAMs) approved by Canadian regulators, including the previously BCUC-approved AAM, which has long been calibrated to forecast bond yields rather than current bond yields.[361]

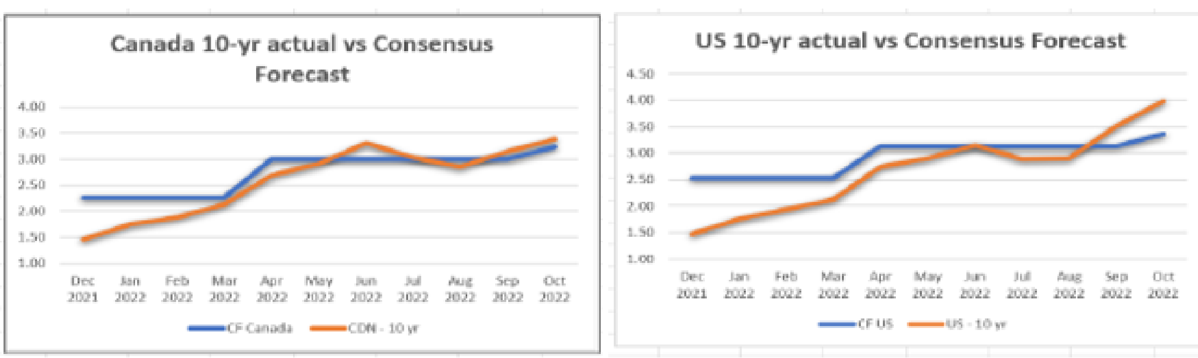
Regarding Dr. Lesser's view that based on the Efficient Market Hypothesis, "using a forecast of future yields on such bonds thus amounts to "double-counting" future expectations."[362] FortisBC remarks that Dr. Lesser concedes that "double- counting" is a misnomer, as Mr. Coyne is using the forecast instead of current bond yields (not adding them together). FortisBC also notes that Dr. Lesser acknowledges that investors look beyond the current price to inform investment decisions.[363]

In FortisBC's view, the reality is that current prices reflect many considerations other than investor expectations about the future, such as institutional investors settling trades at prices based on portfolio requirements:[364]

> A bond yield market is a chaotic place. There are billions and trillions of dollars traded each day in bond markets. Some traders have to get into positions, they have to get out of positions. They're optimizing what they need to do in that moment. That's different than having a three-to-five year outlook on what those markets are going to be.

FortisBC points out that forecast yields are now below the actual yields in both Canada and the US (see Figure 1). Thus, accepting Dr. Lesser's recommendation would, all else equal, increase Mr. Coyne's CAPM values. Dr. Lesser also agrees that Figure 1 shows that, regardless of whether one uses current or forecast bond yields, the cost of capital has increased since December 2021.[365]

Figure 1: Canada and U.S. 10-Yr Actual vs Consensus Forecast[366]



[361] FortisBC Final Argument, pp. 156–158.
[362] Exhibit A2-3, p. 46.
[363] FortisBC Final Argument, p. 158.
[364] FortisBC Final Argument, p. 158–159.
[365] Ibid., p. 161.
[366] Ibid., p. 162.

FortisBC submits that it is important to resolve this issue on a theoretical defensible basis, even if that means Mr. Coyne's CAPM results are lower than they otherwise would be if the BCUC were to adopt Dr. Lesser's recommendation.

Positions of Parties

ICG

Based on its support for the Efficient Market Hypothesis, ICG submits that model inputs should be based on current market prices rather than forecasts.[367]

BCOAPO

BCOAPO does not support or reject either expert's approach and notes that the results based on the October 2022 data are similar between the two experts, so provided that the BCUC uses the October 2022 data set to determine the ROE, there appears to be little difference in the risk-free rate regardless of which approach was used. However, this conclusion is entirely dependent upon the time period the BCUC chooses so BCOAPO submits that the approach chosen by the BCUC is important due to its potential influence on future panels.[368]

The CEC

The CEC notes that the experts disagree on the use of current government bond yields (Dr. Lesser) versus forecast government bond yields (Mr. Coyne) to determine the risk-free rate. The CEC submits that Dr. Lesser's concern with using data that may double-count investors' expectations has an important degree of validity. However, the CEC notes that the differences in the results are relatively small and that Mr. Coyne's choice appears to be the more conservative outcome. Therefore, the CEC supports Mr. Coyne's choice of forecast bond yields.[369]

RCIA

On the risk-free rate, RCIA notes that the debate is focused on whether to include a blend of actual and forecast rates (Mr. Coyne's method) or to use only actual rates (Dr. Lesser's). RCIA notes that any difference in risk-free rate estimates due to different assumptions will be 100 percent reflected in the calculated ROE based on the CAPM formula. Referencing the December 2021 and September 2022 data, RCIA concludes that the adoption of Mr. Coyne's assumptions regarding the risk-free rate results in a calculated ROE difference that does not track with actual changes in interest rates.[370] RCIA recommends adjusting Mr. Coyne's CAPM calculation by incorporating only actual risk-free rate data. [371]

FortisBC Reply Argument

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[367] ICG Final Argument, pp. 6, 8.
[368] BCOAPO Final Argument, pp. 44–46.
[369] The CEC Final Argument, p. 41.
[370] RCIA Final Argument, pp. 11–14.
[371] Ibid., p. 20.

In reply to ICG's suggestion that using forecast bond yields is a rejection of the Efficient Market Hypothesis that underlies cost of capital models, FortisBC notes Mr. Coyne's observation that today's price not only incorporates future expectations but also additional investment considerations unrelated to what investors expect the price will be in the future. Were this not the case, there would be consistent alignment between current prices and forecasts. FortisBC states that this is one instance where clinging inflexibly to the academic Efficient Market Hypothesis is unhelpful to achieving a fair real-world result, considering that the Fair Return Standard is grounded in real-world considerations. FortisBC also points out that ICG's support for the rigid application of the Efficient Market Hypothesis in relation to risk-free rate is inconsistent with ICG's acceptance of using forecast bond yields in an AAM context.[372]

In response to RCIA, FortisBC notes that RCIA mischaracterized the nature of the disagreement between Mr. Coyne and Dr. Lesser on the risk-free rate when suggesting that Mr. Coyne proposed to use a blend of forecast and actual data. FortisBC points out that Mr. Coyne only used forecast bond yields. FortisBC also remarks that RCIA's focus on *ex post* forecast accuracy to oppose the use of forecasts because they are "fraught with uncertainty" misses the point. FortisBC states that the use of forecast bond yields recognizes that cost of capital is dictated by forward-looking investor expectation, and investors use forecasts.[373]

FortisBC also points out that RCIA uses the December 2021 data, despite the experts' agreement to use October 2022 data. Both forecast and actual bond yields increased significantly between these dates and FortisBC demonstrates that the differential between forecast and actual bond yield reverses in October 2022 such that the CAPM results based on actual bond yields rather than forecast bond yield would be 24 basis points (bps) higher, based on October 2022 data.[374]

Panel Determination

The risk-free rate is a key input in the CAPM, representing an estimate of the risk-free return that investors can expect to earn. Both experts agree that it is appropriate to base the estimated risk-free rate of return on the yield on long-term government bonds using a 30-year timeframe. None of the parties object to this approach. The Panel accepts this approach and notes that it is consistent with previous BCUC cost of capital decisions. We also recognize that the use of long-term rates is common in regulatory settings given that the rate of return is typically set for a longer period.

The experts disagree, however, on whether to estimate the risk-free rate using current or forecast bond yields. Consistent with views accepted in the 2016 FEI COC proceeding, Mr. Coyne states in his December 2021 evidence that since bond yields remain near historical lows, rates then do not reflect forward-looking circumstances because investors are factoring higher interest rates into their longer-term expectations and required returns. On the other hand, Dr. Lesser argues that the current yield already reflects investors' collective expectations about interest rates. ICG and RCIA support using current yields. The CEC and BCOAPO both note that the estimated risk-free rates using October 2022 data are similar between the two experts. Given we have already determined that using the October 2022 data is appropriate, we agree with BCOAPO that there appears to be little difference in the estimated risk-free rate regardless of which approach is used. This is especially the

[372] FortisBC Reply Argument, pp. 63–64.
[373] FortisBC Reply Argument, pp. 62–63.
[374] Ibid., p. 62.

case when using the 90-day average. Since recent increases in interest rates have impacted October 2022 results, we consider it reasonable to use the slightly longer 90-day period suggested by Dr. Lesser.

FortisBC points out that because the current yields are higher than the forecast yields in October 2022, Mr. Coyne's CAPM results are lower than they would be if the BCUC were to adopt Dr. Lesser's recommendation to use the current yield. Even though there is only a small difference between the current and forecast yields, FortisBC considers that the Panel should decide the "conceptually important issue" and argues that Mr. Coyne's forecast approach best reflects how investors make decisions because the current yield reflects additional investment considerations unrelated to what investors expect the price will be in the future. However, the Panel does not agree it is necessary to conclude on this issue for the purpose of setting the appropriate ROE for FEI and FBC in this proceeding because the October 2022 actual and forecast rates are closely aligned and interest rates are now trending above the historic lows in December 2021 that Mr. Coyne referred to.

We note that Mr. Coyne uses the forecast Canadian risk-free rate of 3.21 percent for the Canadian utilities in the North American proxy group and the forecast US risk-free rate of 3.50 percent for the US utilities in the North American proxy group. In Section 3.2, the Panel determined that it is appropriate to remove two Canadian utilities from the North American proxy groups and as a result, the risk-free rate would be weighted more towards the US risk-free rate than the Canadian risk-free rate. The Panel will consider the overall impact of this in Section 5.2.5 on Overall CAPM Results.

Based on the above determinations and subject to any adjustment noted in Section 5.2.5, **the Panel finds that Mr. Coyne's estimated risk-free rate based on forecast long-term government bond yields for his CAPM estimate is reasonable.**

5.2.2 Beta

Beta is the systematic risk of an individual security and represents the risk of the security relative to the market. Mr. Coyne employs several methods of measuring the beta coefficient for the Canadian and US proxy groups using estimates from both Value Line and Bloomberg. Mr. Coyne explains that:

- Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index;
- Bloomberg produces beta estimates based on parameters entered by the user and Mr. Coyne computed Bloomberg betas based on five years of weekly stock returns and using the S&P 500 or the S&P/Toronto Stock Exchange (TSX) Composite as the market index; and
- Both Value Line and Bloomberg report adjusted betas.[375]

The following table presents the adjusted betas used by Mr. Coyne in his CAPM.

[375] Exhibit B-1-8-1, Appendix C, p. 57.

Table 12: Value Line and Bloomberg Betas[376]

October 2022	Value Line	Bloomberg
Canadian Group	0.80	0.88
U.S. Gas Group	0.84	0.80
North American Gas Group	0.84	0.88
U.S. Electric Group	0.89	0.89
North American Electric Group	0.88	0.86

Raw versus Adjusted Betas

Both experts recommend the use of Blume-adjusted betas to reflect a forward view of betas and their tendency to migrate toward the market mean over time, which is consistent with the forward-looking nature of estimating the allowed ROE for a utility.[377] Mr. Coyne also notes that both US utility regulators, including FERC, and the Brattle Group's 2012 study conducted for the BCUC also support the use of Blume-adjusted betas.[378]

One area of difference between the two experts is their data sources for adjusted betas. Mr. Coyne relies on Value Line and Bloomberg whereas Dr. Lesser recommends to only use Value Line to ensure consistency amongst all CAPM estimates,[379] as he notes that published betas can differ for the same firm due to differing estimating methods, historical periods, and data frequency being used.[380] However, Dr. Lesser also cautions that disputes over which published beta is "better," or whether practitioners should estimate their own betas, is likely to complicate the process for setting the allowed return.[381]

Despite Dr. Lesser's position, the evidence shows that Value Line does not publish adjusted betas for four out of six utilities included in Mr. Coyne's Canadian proxy groups.[382]

Adjusting Beta for Differences in Leverage

Dr. Lesser notes that, when applying the CAPM estimates of the proxy group to the utility under review, the differences in leverage must be accounted for.[383] If the capital structures of the proxy group firms differ significantly from the utility under review, as is the case for FEI and FBC, then the resulting CAPM estimates will not necessarily provide an accurate estimate of the required ROE.[384] For example, FEI's current deemed equity ratio is 38.5 percent while the average deemed equity ratio for the US gas proxy group is 53.4 percent.[385] To do this, the levered betas of the proxy group firms are unlevered to remove the financial risk component. The

[376] Information in the table has been compiled from Exhibit B1-50, Attachments A.2 FBC Electric, Tab "JMC-FBC-8.1 Avg CAPM" and FEI Gas, Tab "JMC-FEI-6.1 Avg CAPM".
[377] Exhibit B1-8-1, Appendix C, p. 59, Exhibit A2-20, BCUC IR 7.1, Exhibit A2-3, p. 42.
[378] Ibid., pp. 58–59.
[379] Exhibit B1-8-1, Appendix C, p. 59, Exhibit A2-20, BCUC IR 7.1.
[380] Exhibit A2-3, p. 41.
[381] Exhibit A2-20, BCUC IR 7.1.
[382] Exhibit B1-50, Excel Model A.2, Gas – Tab 6.1 and Electric – Tab 8.1.
[383] Exhibit A2-3, p. 43.
[384] Ibid.
[385] Exhibit B1-8-1, Appendix C, p. 120.

resulting beta values are called, asset betas. Next, these asset betas are re-levered using the capital structure of the regulated utility under rate review.[386] This can be done using the Hamada formula, shown below:[387, 388]

$$\beta_E = \beta_A \times \left[1 + (1 - t) \times \frac{D}{E}\right] \qquad (2)$$

Where

β_E = the firm's pure equity beta
β_A = the firm's observed asset beta
D = the firm's amount of outstanding debt
E = the value of the firm's equity capital

In contrast, Mr. Coyne does not include an adjustment for leverage in his CAPM modelling because of his proposal to increase the equity ratio for FEI, reducing the disparity with those of the proxy groups and retaining FBC's existing equity ratio.[389] Mr. Coyne states that if the Hamada formula is used, as Dr. Lesser indicates is appropriate, the CAPM results for the US gas and US electric proxy groups are higher due to differences in the equity ratio between those proxy groups and the utilities under review.[390]

FortisBC notes that Mr. Coyne confirms his "complete alignment" with Dr. Lesser regarding the need to account for disparities in financial risk and the methods to do so (i.e. the Hamada adjustment to adjust the ROE in the CAPM analysis). Since FEI and FBC currently have significantly lower common equity ratios relative to the proxy group companies, the Hamada adjustment would increase the ROE relative to the one suggested by Mr. Coyne's model outputs. However, Mr. Coyne did not adjust the ROE results upwards to account for FEI and FBC's thinner equity. Instead, he has chosen to address the discrepancy in financial risk through his recommended capital structure because he notes that this is most consistent with how the BCUC typically accounts for differences in relative risk.[391]

Consequently, FortisBC highlights this issue as an important take-away for the BCUC. FortisBC submits that the BCUC cannot approve a common equity ratio below 45 percent for FEI and 40 percent for FBC without also adjusting the CAPM results upwards. This upward adjustment in ROE would be necessary to offset the larger disparity in financial risk.[392]

Positions of Parties

<u>BCOAPO</u>

On the topic of beta values, BCOAPO notes the agreement of both experts to use adjusted betas as opposed to raw betas and their reliance on different data sources for their betas. BCOAPO states that beta estimates are not

386 Exhibit A2-3, p. 43.
387 Ibid., pp. 43-44.
388 The steps are: 1) the levered betas of the proxy group firms are unlevered to remove the financial risk component; and 2) the resulting betas (asset betas) are re-levered using the capital structure of the regulated utility under review. (Exhibit A2-35, p. 43).
389 Transcript Volume 3, pp. 271–274.
390 Exhibit B1-8-1, Appendix C, p. 59.
391 FortisBC Final Argument, pp. 174–175.
392 Ibid., pp. 176–177.

available from Value Line for all the gas and electric utilities included in Mr. Coyne's proxy groups and notes that, where values were available from both Value Line and Bloomberg, neither source consistently provides higher or lower values. Therefore, BCOAPO submits that Mr. Coyne's approach to use the average of values published by Value Line and Bloomberg is more appropriate.[393]

Furthermore, BCOAPO notes that both experts agree that it is possible to consider differences in financial leverage between the proxy groups' companies and FEI and FBC by adjusting the authorized ROE. While not specifically addressing the CAPM, BCOAPO also submits that, in conjunction with its recommended increase in deemed equity from 38.5 percent to between 40 to 42 percent, it would be reasonable to help recognize the differences in financial leverage between FEI and the North American gas proxy group by increasing FEI's ROE to 9.50 percent from the 9.38 percent calculated using the models.[394]

In order to help recognize both the financial leverage difference between FBC and the North American electric proxy group and the implications that size difference has on the CAPM results, BCOAPO submits that it would be reasonable for the BCUC to set FBC's authorized ROE at 9.5 percent as opposed to 9.01 percent as calculated using the models.[395]

<u>The CEC</u>

The CEC finds that, on balance, the evidence before the BCUC does not support additional adders to the FEI and FBC ROEs for differences in financial leverage and does not support, at this time, moving the equity thicknesses to those of the US proxy groups.[396] The CEC recommends that the BCUC remain sensitive to the trade-offs between equity thickness and the allowed ROEs, and consider in its AAM processes the possibility for both to be reviewed and adjusted on a formulaic basis.[397]

<u>RCIA</u>

Regarding the beta values, since there do not appear to be significant differences in the assumptions of the two experts, RCIA is not opposed to the beta values used by Mr. Coyne.[398]

<u>FortisBC Reply Argument</u>

In reply, FortisBC notes that BCOAPO acknowledges that there is a need to adjust the ROE upwards for FEI's relative financial risk compared to proxy groups, and states that BCOAPO's ROE recommendations include such an adjustment. BCOAPO does not state explicitly how much of an upward adjustment it has included for FEI's ROE but FEI states that this amount can be readily back-calculated as being only 12 bps. FortisBC submits that this is clearly insufficient, as a Hamada adjustment would increase the ROE by almost four times that amount.[399]

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[393] BCOAPO Final Argument, p. 51.
[394] Ibid., p. 58.
[395] Ibid.
[396] The CEC Final Argument, p. 54.
[397] Ibid., p. 55.
[398] RCIA Final Argument, p. 11.
[399] FortisBC Reply Argument, p. 46.

Panel Determination

Beta is a key input into the CAPM and relies on a proxy group of companies to estimate the risk of FEI and FBC compared to the whole market. Consistent with common practice, Mr. Coyne uses five years of data in his analysis. His estimates are based on data from two credible third-party sources (Value Line and Bloomberg). In contrast, Dr. Lesser prefers to only use Value Line data to ensure consistency amongst all CAPM estimates. However, the evidence shows that Value Line does not publish adjusted betas for several of the utilities included in Mr. Coyne's Canadian proxy groups. Given this, the Panel agrees with BCOAPO that since there appears to be no upward or downward bias in either source of data, Mr. Coyne's approach using the average of values published by Value Line and Bloomberg is reasonable.

In Section 3.2, the Panel determines it appropriate to remove two Canadian utilities from the Mr. Coyne's North American proxy groups in accordance with BCOAPO's proposal to remove Enbridge Inc. and Canadian Utilities Limited which, since as stated by Mr. Coyne during the oral hearing, these companies were unlikely to have passed his screening criteria if applied strictly. This change impacts the overall beta result. The Panel will consider the overall impact of this in Section 5.2.5 on Overall CAPM Results.

Both experts agree that it is appropriate to use Blume-adjusted betas to reflect a forward-looking view and to adjust the raw data for the observed tendency of betas to migrate toward the market mean over time. Consistent with the views of the experts, the use of adjusted betas is accepted by US utility regulators, including FERC.

Mr. Coyne states that he is not aware of any Canadian jurisdiction that has specifically endorsed the use of Blume adjusted betas.[50] The BCUC has not accepted Blume-adjusted betas in previous proceedings. In the 2016 Decision, the BCUC placed limited weight on the experts' adjustments to beta because of a lack of empirical evidence supporting the applicability of the Blume adjustment to utility stocks.[51] Likewise, in the 2013 Decision, the BCUC stated:

> An adjustment of beta to the market average of one seems inconsistent with the lower risk in the industry, while realized return seems to indicate a beta that exceeds the industry average. The Panel finds that none of the positions fully explain the beta value and therefore accepts an intermediate beta estimate of 0.6 representing the range of reasonable estimates presented.[52]

However, the Panel notes Mr. Coyne's explanation that Dr. Blume found that his adjustment was applicable to all betas, ranging from a low of 0.50 to a high of 1.53, and in Mr. Coyne's view, there is no reason to expect that regulated utilities would be an exception to this rule.[53] Given the views of the two experts in this proceeding and since none of the parties object to Mr. Coyne's use of Blume-adjusted data, the Panel accepts the experts' recommendation to use the Blume-adjusted beta estimates for the proxy groups.

The Panel agrees with the experts that there is a need to account for leverage differences in the proxy group of companies and acknowledges that the Hamada adjustment is an appropriate approach to adjust for FEI and FBC's thinner equity. However, given that Mr. Coyne did not provide an October 31, 2022 update identifying the impact of the Hamada adjustment on his CAPM results, we accept Mr. Coyne's approach to addressing the discrepancy in financial risk through an adjustment to the capital structure. We agree this approach is consistent with how the BCUC typically accounts for relative risk. In determining an appropriate capital structure for FEI and FBC as set out in Section 6.3, we acknowledge FortisBC's submission that Mr. Coyne's CAPM results are based on a common equity ratio of 45 percent for FEI and 40 percent for FBC.

5.2.3 Market Risk Premium

The MRP is the difference between the expected total return on a broad market portfolio and the return on the risk-free investment. Mr. Coyne describes the MRP as the amount that investors expect to earn above the risk-free rate as compensation for owning common stock, which is considered higher risk than government bonds.

To estimate the MRP, Mr. Coyne explains that:

- Estimates of the MRP generally fall into two categories, ex-post (historical arithmetic average) and ex-ante (forward-looking);
- The historical MRP is based on the arithmetic mean of the average annual return on large company stocks less the income-only return on long-term government bonds based on historical data from Duff & Phelps, a well-respected source of financial information for investors;
- The forward-looking MRP is calculated by subtracting the risk-free rate from the estimated total return for the overall market, using a DCF model applied to a proxy group for the market as a whole, such as the S&P 500 or the TSX; and
- First, an overall expected market return is estimated. Then, the risk-free rate is subtracted to get the MRP.[400]

Both experts acknowledge that the MRP can be calculated on either an historical or forecast basis.[401] Dr. Lesser notes that it is acceptable to average an historical MRP with a forward-looking MRP, using Mr. Coyne's methodology, if the forward-looking MRP is estimated using a reasonable methodology. However, Dr. Lesser does not consider the single-stage DCF approach (also known as the constant DCF approach) used by Mr. Coyne to be a reasonable approach to estimate a forward-looking MRP.[402]

Constant versus Multi-Stage DCF Model to Estimate the MRP

As noted above, a key area of difference between the two experts is whether to estimate the forward-looking MRP using the Constant DCF model, as advocated by Mr. Coyne, or the Multi-Stage DCF model, as preferred by Dr. Lesser.[403]

Mr. Coyne notes that a constant-DCF approach is consistent with the method used by FERC.[404] This method applies a single-stage DCF to the dividend-paying firms of the S&P 500 to estimate the market return and MRP, which Mr. Coyne considers appropriate because: (i) the S&P is updated regularly to remove slow-growing firms and (ii) that even though an individual company cannot sustain high growth rates forever, a broad market index can do so. The Constant DCF model employed by Mr. Coyne uses analyst growth forecasts for the S&P 500 and

[400] Exhibit B1-8-1, Appendix C, pp. 59–60.
[401] Exhibit B1-8-1, Appendix C, p. 60, Exhibit A2-5, BCOAPO IR 8.1.
[402] Exhibit A2-24, BCOAPO IR 18.4.4.
[403] Exhibit B-21, p. 5.
[404] Exhibit B1-8-1, Appendix C, p. 61.

TSX because those estimates reflect expectations of what an investor could earn by investing long-term in those indices. The analyst growth forecasts generally refer to a period of between three to five years.[405]

Dr. Lesser cautions regulators adopting the forward-looking approach to be aware that using a Constant DCF model is likely to yield estimates of market returns that are unreasonably high and statistically improbable.[406] In Dr. Lesser's opinion, FERC's rationale is based on a misconception. He explains:

> Using the expected returns for the S&P 500 or the TSX represent a proxy for the entire market. […] In the long-run, the market cannot grow faster than the economy as a whole for the simple reason that the market, in effect, is the economy.[407]

In response, Mr. Coyne points to his evidence that the historical growth rates of regulated utilities in Canada and the US as measured by earnings per share and dividends per share growth, have been higher than nominal growth domestic product (GDP) over 2005 to 2019, which also supports a view that the broad market can increase by more than the level of GDP growth (since utilities are generally slower growth companies). Mr. Coyne also states that since the S&P 500 consists of the most successful companies, they should not be expected to represent the economy overall, as implied by GDP.[408] However, Dr. Lesser disagrees with Mr. Coyne on this as he explains that, under the CAPM, the expected return in the market refers to the return on all publicly traded securities, not just a single proxy group such as the S&P 500:

> Mr. Coyne's "evidence" that the growth in the S&P 500 has exceeded GDP growth is therefore irrelevant. The entire market cannot grow faster than the economy in the long-run because the entire market effectively is the economy.[409]

Average of historical and forward-looking MRP versus forward-looking only MRP

Mr. Coyne uses an average of the historical MRP[410] and the forward-looking MRP across both Canada and the US Dr. Lesser relies on a country-specific, forward-looking MRP only.[411] Dr. Lesser recommends the use of a Canadian MRP for the Canadian proxy group, a US MRP for the US proxy groups, and an average of the two countries' MRP for the North American proxy groups.[412]

Mr. Coyne justifies his "averaging" method on the fact that the two economies are highly integrated and capital flows freely between them. Thus, the risk premiums for each country are highly correlated such that it is reasonable to derive a single forward-looking MRP estimate for both countries by averaging the four estimates.[413]

[405] Exhibit B1-9, BCUC IR 39.8.2.
[406] Exhibit A2-3, p. 52.
[407] Ibid.
[408] Exhibit B1-9, BCUC IR 39.4.
[409] Exhibit A2-24, BCOAPO IR 18.5.
[410] The historical MRP for the US is calculated over the period from 1926 to 2020, while in Canada, the historical MRP covers the period from 1919 to 2020. Exhibit B1-9, BCUC IR 40.1.
[411] Exhibit B1-21, pp. 17–18, Exhibit B1-8-1, Appendix C, p. 60.
[412] Transcript Volume 3, p. 211, Lines 1–6.
[413] Exhibit B1-8-1, Appendix C, p. 60.

In addition, Mr. Coyne explains that given the low-rate environment in December 2021, he would tend to place more reliance on the forward-looking MRP in the CAPM analysis. Mr. Coyne points to FERC's exclusive reliance on a forward-looking MRP in the CAPM and to Dr. Lesser's support for the use of a forward-looking MRP.[414] Despite this view, Mr. Coyne still proposes to take a simple average of these four estimates to estimate the MRP, citing the fact that there is a lot of controversy in Canada around what is the forward-looking MRP. By averaging both the historical and forward-looking MRPs, Mr. Coyne, brings both perspectives into play, stating, "being sympathetic to those who would argue that 100 years of history means something". Mr. Coyne continues and states, "if left to my own druthers absent that debate I'd probably give [the forward approach] 100 percent weight."[415]

The following table presents Mr. Coyne's historical and forward-looking MRPs for Canada and the US based on October 2022 data, where Mr. Coyne uses the Constant DCF model to derive the forward-looking MRPs.

Table 13: Market Risk Premiums – Canada and U.S. – October 2022[416]

	Canadian MRP	U.S. MRP
Historical	5.74%	7.46%
Forward-Looking	7.74%	8.21%
Average	7.29%	

In comparison, the forward-looking-only MRPs derived by Mr. Coyne using his interpretation of Dr. Lesser's preferred approach, i.e. the Multi-Stage DCF model, are shown in the table below. This approach to calculating the MRPs yields significantly lower MRPs than Mr. Coyne's and has a commensurate impact on the overall CAPM estimates.

Table 14: Market Risk Premiums – Canada and U.S. – October 2022[417]

Forward-looking MRP	**Canada**	**U.S.**
	October 2022	
30-day	5.47%	3.30%
90-day	5.66%	3.78%

FortisBC submits that the experts agree that the forward-looking MRP should be computed based on the total return on the S&P 500 Index (for US proxy groups) and the TSX (for Canadian proxy groups) but disagree on how to compute it. Fortis BC states that Mr. Coyne uses the Constant DCF model, like FERC, moderated by giving 50 percent weighting to historical data. FortisBC argues that Mr. Coyne's "very conservative approach" of averaging the constant growth DCF forward-looking MRP with historical returns is a concession to past controversy about how to forecast the forward-looking MRP.[418] FortisBC argues that although Dr. Lesser previously shared Mr.

[414] Exhibit B1-8-1, Appendix C, pp. 60–62.
[415] Transcript Volume 3, p. 217, Lines 21–15 to p. 218, Lines 1–14.
[416] Exhibit B1-50, Attachment A.2 FBC – Electric (Oct 2022 update 90 day), Tab JMC-FBC-8.1 Avg CAPM, Cell G6 or Attachment A.2 FEI – Gas (Oct 2022 update 90 day), Tab JMC-FEI-6.1 Avg CAPM, Cell G6.
[417] Information in the table has been compiled from Exhibit B1-50, Table 1, p. 2.
[418] FortisBC Final Argument, pp. 163–164.

Coyne's approach, he now advocates for a Multi-Stage DCF model, which is the reason for the very low Lesser CAPM result.[419]

FortisBC argues that applying Dr. Lesser's methodology and assuming that companies in the S&P 500 are only going to grow at the rate of GDP growth starting in Year 6 is not realistic. FortisBC notes that Dr. Lesser states that "companies absolutely can grow faster than GDP after five years".[420] FortisBC submits that Mr. Coyne provided evidence to back that up, showing that over a 92-year period (1929 to 2020), average annual returns on large company stocks have exceeded nominal GDP growth by 5.55 percent and that earnings per share (EPS) and dividend per share (DPS) of regulated utilities in Canada and the US grew faster than nominal GDP over the period 2005 to 2019. Since utility companies are generally slower growth companies, Mr. Coyne observes that it stands to reason that the broad market can also increase by more than the level of GDP growth.[421]

FortisBC submits that the forward-looking only MRPs derived from using Dr. Lesser's preferred approach produces an MRP that "defies logic":[422]

> A U.S. MRP of 3.30% or 3.78% […] is outside any reasonable range of the MRP estimates and 3.5% to 4.0% lower than the historical U.S. MRP of 7.46% from 1929-2021. […]
>
> Using Dr. Lesser's method for calculating the forward-looking MRP produces CAPM results that are well below the multi-stage DCF model results, the constant growth DCF results and the risk premium model results. This calls into question the reliability of the CAPM results using Dr. Lesser's inputs.

Positions of Parties

ICG

ICG notes that Mr. Coyne used the same approach for estimating the MRP in a testimony before the Alberta Utilities Commission (AUC) and that the AUC rejected Mr. Coyne's approach to calculating the MRP for the CAPM by giving it no weight because of unsupported and very high ROE recommendations. ICG submits that the BCUC should do the same. And although FERC also uses a Constant Growth DCF MRP, Dr. Lesser provides a comprehensive explanation as to why he does not support that approach.[423]

BCOAPO

BCOAPO submits that Mr. Coyne's argument in favour of using the Constant DCF model to estimate the forward-looking MRP is flawed. BCOAPO explains that an MRP is supposed to be based on the expected returns of the overall market, but indices like the S&P 500 do not represent the overall market and even the S&P 500 is biased, as it only includes companies with high capitalization.[424] Thus, BCOAPO submits that the Panel should consider results from the CAPM where the MRP is based on a Multi-Stage DCF model as recommended by Dr. Lesser.

[419] FortisBC Final Argument, pp. 162–163, 167.
[420] Ibid., p. 165.
[421] Ibid., p. 165–166.
[422] FortisBC Final Argument, p. 166–167.
[423] ICG Final Argument, pp. 3, 11, 13, 15.
[424] BCOAPO Final Argument, p. 50.

Furthermore, BCOAPO submits that a more appropriate way to compare Mr. Coyne and Dr. Lesser's CAPM results would be to apply Mr. Coyne's averaging of historic and forecast MRP values to Dr. Lesser's CAPM methodology. In this way, BCOAPO submits that the Panel can compare apples to apples.[425] BCOAPO recalculates the "Lesser CAPM results" by replacing the MRP values with the average of the historic and forward-looking values. The BCOAPO-revised results are shown as "Lesser – Average CAPM (BCOAPO)" in the following table:

Table 15: BCOAPO Summary of CAPM ROE (excluding flotation costs) – October 2022 (90- Days)[426]

Proxy Groups:	Canada	U.S. Electric	NA Electric	U.S. Gas	NA Gas
Coyne – Average CAPM	9.62%	9.46%	9.80%	10.01%	9.74%
Lesser – Average CAPM (BCOAPO)	8.09%	8.45%	8.23%	8.03%	8.27%

BCOAPO concludes that "[j]ust as averaging tends to bring Mr. Coyne's results closer to those produced by the Multi-Stage DCF model, averaging also does the same for Dr. Lesser's. As a result, just as Mr. Coyne has characterized his use of averaging as "more conservative than relying solely on the forward-looking MRP", the same could be said for the use of averaging in Dr. Lesser's approach."[427]

The CEC

The CEC submits that Mr. Coyne's 50 percent split (between historical and forward-looking) helps moderate the result, and the CEC would support a weighting for additional historical data and lower weighting for the forward-looking data, which could justify a 70 to 90 bps reduction for the modelling data.[428]

The CEC also recommends that the BCUC adjust its overall ROEs for FEI and FBC downward by 80 bps for the CEC's perception that the modelling results are too forward looking and should be more grounded in the current and historical data.[429]

Regarding the use of the DCF model to estimate the MRP, the CEC notes that Dr. Lesser proposes the Multi-Stage DCF model whereas Mr. Coyne uses the Constant DCF model. The CEC states that Dr. Lesser's approach to limiting forecast market returns to five years and in Year 6 using forecast GDP was debated, with Mr. Coyne providing evidence showing that average returns on large company stocks, and even on regulated Canadian and US utilities, exceeded GDP growth historically. Based on these observations, the CEC submits that the arguments of Mr. Coyne appear to have merit for his CAPM modelling and that Dr. Lesser's CAPM modelling should not be used. The CEC does not support the view that the market is the economy and that it therefore cannot grow more than the GDP of a country in which that market operates (i.e. Dr. Lesser's view).[430]

[425] BCOAPO Final Argument, p. 49.
[426] BCOAPO Final Argument, p. 49.
[427] Ibid., p. 50.
[428] The CEC Final Argument, p. 41.
[429] Ibid., p. 43.
[430] Ibid., pp. 41–42.

RCIA

RCIA notes that the Canadian MRP, both historic and forward looking, is markedly lower than the US MRP. While Mr. Coyne justifies averaging the four MRP estimates to use in his CAPM formula based on the highly integrated nature of the Canadian and US markets, RCIA submits that there is no evidence to suggest that this integration is not already reflected within the respective market calculated MRP values.

RCIA also submits that the Canadian MRP should only be measured against the Canadian proxy group as being country (and market) specific. RCIA shows that the average of the historic Canadian MRP (5.54 percent) and the historic U.S MRP (7.25 percent) results in an MRP of 6.40 percent. Thus, Mr. Coyne's CAPM results are biased upwards by 77 bps relative to a Canadian-only MRP.[431] Although RCIA does not support the inclusion of US data in the calculation of ROE for FEI and FBC, if the BCUC were to accept it, RCIA submits that there is no evidence to support an equal weighing of Canadian and US data.[432]

In addition, RCIA comments on Mr. Coyne's approach to averaging both historic and forward-looking MRPs. RCIA notes that, while the historical US MRP was 7.25 percent over the 1926 to 2022 period, Mr. Coyne calculates and assumes that the difference between the stock market performance and the US bond yield will average 12.08 percent on a forward-looking basis. RCIA then cites Dr. Lesser's evidence that "forward market risk premiums that might be 12 or 13 percent" are in his view "a statistical impossibility".[433] Further, RCIA notes that Mr. Coyne's average MRP of 8.49 percent above the risk-free rate seems highly questionable when looking at historical Canadian MRPs.[434] RCIA concludes that in the context of a Canadian utility, Mr. Coyne's forward-looking MRP assumptions are not an impossibility, but history suggests them to be quite improbable.[435]

RCIA recalculates the average MRP based only on Canadian historic and forward-looking MRP and obtains 7.32 percent. RCIA points out that this level would have been exceeded only twice in the last ten decades. Thus, RCIA submits that Mr. Coyne's assumption of equal weighting of historical and forward-looking MRP biases the resulting MRP upward. RCIA submits that a much lower weighting of the forward-looking MRP may be appropriate such as 75 percent historical and 25 percent forward-looking. A 75-25 blending of Canadian historical and Canadian forward-looking MRPs results in an MRP assumption of 6.43 percent.[436] RCIA states this estimate would have been exceeded three times over the past ten decades. Thus, RCIA recommends using a 75-25 weighting as opposed to the 50-50 weighting of only Canadian data as it provides a better directional alignment with the available data. Based on Concentric's beta of 0.89, the CAPM result under this weighting would be approximately 79 bps lower than one derived from an equal weighting of historical and forward-looking data.[437,438]

[431] The difference (6.40 % - 5.54 %) multiplied by a beta of 0.89 equals 77 bps.
[432] RCIA Final Argument, pp. 15–17.
[433] Ibid., pp. 17–18.
[434] Ibid., p. 18.
[435] Ibid., pp. 18–19.
[436] 0.75 x 5.54% + 0.25 x 9.10% = 6.43%.
[437] (7.32%-6.43%) x 0.89 (Beta).
[438] RCIA Final Argument, p. 19.

FortisBC Reply Argument

In reply, FortisBC submits that ICG has misinterpreted the AUC's approach in the AUC 2018 Decision cited by ICG. In that decision, the AUC rejected all forward-looking DCF estimates, both single and multi-stage, in favour of relying exclusively on historical MRP data. Thus, using the AUC approach in the context of this GCOC proceeding would produce a higher MRP than Dr. Lesser's since historical MRPs are higher than MRPs calculated using a two-stage approach. FortisBC adds that there is no evidence on record showing that investors' expected return is equal to historical returns and as such, there is no support to rely only on historical MRPs like the AUC did in 2018.[439]

FortisBC also rejects BCOAPO's critique of using the Constant Growth DCF model to estimate the MRP as being flawed. FortisBC notes both experts' agreement that broad market indices (e.g. S&P 500) can be used as proxy for the entire market and that the evidence shows that these indices can and do grow more than GDP over long periods.[440]

FortisBC also submits that, while BCOAPO acknowledges an increase in the cost of capital since the last GCOC proceeding, its calculations still understate the required ROE due to their reliance on the Lesser CAPM result and mathematical errors.[441] FortisBC reiterates that the Lesser CAPM results are implausibly low due to a very low MRP and that even Dr. Lesser questions the validity of such low ROE results. Including unreasonably low results in an average, as BCOAPO has done, also makes the resulting average unreasonably low.

FortisBC states that BCOAPO implicitly acknowledges that the two-stage CAPM results are unreasonable because they adjust the forward-looking MRP upwards by averaging the forecast MRP with the historical average MRP. As BCOAPO notes, Mr. Coyne's CAPM results were already conservative due to his decision to base the MRP on a 50:50 blend of forecast and historical data. FortisBC concludes, there is no need to average Mr. Coyne's conservative CAPM results with any other CAPM results, adjusted or not. FortisBC states that, while BCOAPO's adjustment reduces the considerable gap between the Lesser CAPM results and every other model and reasonableness check, the adjusted results are still an outlier. Thus, the BCUC should only be using Mr. Coyne's CAPM analysis.[442]

In reply to the CEC, FortisBC explains why the CEC's recommended 80-bps downward adjustment is problematic: a) the CEC conceded that Mr. Coyne is already "conservative" in giving 50 percent weighting to historical MRP data; b) the CEC offers no explanation for how it arrived at this 80-bps adjustment; and c) this deduction is inconsistent with financial theory as CAPM analysis is intended to be forward looking. FortisBC states that it is a big and unjustified leap from the CEC's contention that "investors are not exclusively forward-forecast focused" to placing most of the weight on historical data.[443]

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[439] FortisBC Reply Argument, pp. 69–70.
[440] FortisBC Reply Argument, p. 70.
[441] Ibid., p. 44.
[442] Ibid., pp. 45, 70.
[443] Ibid., pp. 42-43

In response to RCIA's use of Canadian data only for MRP, FortisBC submits that RCIA's view is flawed because:

- An inference cannot be drawn about relative expected returns of utilities in Canada versus the US from a differential in the countries' MRP;
- The MRP is a measure of potential earnings from investing in the market as a whole, not of relative expected returns; and
- The MRP differential between Canada and the US is due to the indices' different industry weightings, not expectations about utility earnings.

FortisBC also notes Dr. Lesser's support for averaging the Canadian and US MRP when looking at North American proxy groups. FortisBC remarks that this averaging approach is potentially conservative, as it would also be reasonable to only use US MRP since a potential investor in FEI/FBC can, as an alternative, obtain the US market return by investing in the S&P 500. FortisBC recalculates RCIA's downward adjustment based on October 2022 data to be 49 bps instead of the 77 bps calculated by RCIA based on December 2021 data.[444]

Furthermore, FortisBC rejects RCIA's assertion that Mr. Coyne's 50:50 approach biases the resulting MRP upwards. Instead, FortisBC considers that giving 50 percent weight to the historical MRP introduces a downward bias of approximately 180 to 190 bps. RCIA's use of a 75:25 blend further suppresses Mr. Coyne's already conservative 50:50 weighting. This is contrary to the consensus expert evidence that the MRP is intended to be forward looking, and Mr. Coyne is clear that his approach is only a pragmatic response to the controversy surrounding MRPs.

Panel Determination

The MRP is a key input into the CAPM. It represents the premium above the risk-free rate that equity investors demand to compensate them for the extra risk they accept when they invest in riskier assets. As Dr. Lesser notes, the theory underlying the CAPM includes all assets in the market (art, real estate, bonds, stocks, etc.). However, the two experts agree that, while there is no perfect proxy for the market, broad market indices such as the S&P 500 and TSX can be used as proxy for the entire market. Given the integration of North American markets, we accept their view, noting that several of the proxy group companies are included in these indices.

Since investor expectations are future focussed, we also support the experts' view that it is appropriate to consider forward-looking estimates in determining the MRP. We also accept that using a DCF approach based on the Bloomberg analysts' long-term growth rate estimates of companies included in the broad market indices is acceptable and is a reasonable starting point for estimating expected market returns. We note that Bloomberg explains that its long-term growth forecasts are received directly from contributing analysts and while different analysts apply different methodologies, the long-term growth forecast generally represents an expected annual increase in operating EPS over the company's next full business cycle. In general, these forecasts refer to a period of between three to five years.[445]

A key determinant for the Panel regarding the forward-looking MRPs is assessing the reasonableness of the growth expectation for the period beyond the five years estimated by analysts. The two experts differ on how to

[444] FortisBC Reply Argument, pp. 64–67.
[445] Exhibit B1-9, BCUC IR 39.8.2.

approach this issue. The Constant DCF model used by Mr. Coyne assumes the three-to-five-year analyst growth forecasts continue in perpetuity. Dr. Lesser prefers a multi-stage DCF approach that reverts to a GDP growth rate at a later stage. He cautions that relying on a constant growth DCF model is likely to yield estimates of market returns that are unreasonably high and statistically improbable.

The Panel places little weight on the two-stage forward-looking MRP model derived by Mr. Coyne based on his interpretation of Dr. Lesser's preferred approach. In this model, Mr. Coyne reverts to a GDP growth rate after five years. We agree that the MRP estimates produced using this assumption are too low and note that Dr. Lesser also questions the results. However, we object to FortisBC's characterization of this output as "the Lesser CAPM result". Dr. Lesser did not prepare this evidence and we do not know what result Dr. Lesser would have presented if he had been engaged to prepare ROE recommendations for FEI and FBC. Given that we place no reliance on the two-stage MRP estimate prepared by Mr. Coyne based on his interpretation of Dr. Lesser's approach, we agree with FortisBC that we should not be adjusting these results in the manner suggested by BCOAPO.

The Panel acknowledges that the evidence shows that market indices can and have grown by more than GDP over long periods. However, we have no evidence to support that investors expect the MRP to grow at the rates reflective of analyst forecasts in perpetuity. Given the recent market volatility and the downturn in market results over the last few years, it is not unreasonable that investors are expecting a higher return over the next five years. However, the Panel is not convinced that what follows is that investors expect an MRP of 8.0 percent[446] in the future compared to the long-term historical average Canadian and US MRP of 6.6 percent.[447]

Accordingly, the Panel must consider the extent to which it should rely on historic MRPs. While Dr. Lesser prefers a forward-looking MRP estimate, he explains that the economic rationale for using an MRP value based on historical data is that the future will resemble the past and the going-forward MRP will be similar to its average value in the past.[448] Mr. Coyne also prefers a forward approach but uses a 50:50 weighting of historic and forward data, "being sympathetic to those who would argue that 100 years of history means something." The Panel notes Mr. Coyne's concern in December 2021 that the historical MRPs would have underestimated the MRP in the then low interest rate environment due to the inverse relationship between interest rates and the MRP.[449] However, the Panel's reliance on October 2022 data, with higher interest rates, should alleviate this concern with using historical data.

FortisBC argues, because there is no evidence on record showing that investors' expected return is equal to historical returns, there is no support to rely only on historical MRPs like the AUC did in 2018 as suggested by ICG or to place greater weight on historical data as argued by RCIA and the CEC. As noted above, we also support the experts' view that it is appropriate to consider forward-looking estimates in determining the MRP. However, we disagree with FortisBC that there is no evidence to support the use of historic returns. As both experts noted, historic returns are regularly accepted as a basis on which to predict future returns. We also disagree with FortisBC that Mr. Coyne's 50 percent weight on historic MRPs is conservative.

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446 (7.74+8.21)/2.
447 (5.74+7.46)/2.
448 Exhibit A2-3, p. 47.
449 Exhibit B1-8-1, Appendix C, p. 60.

In our view, the 50:50 weighting of historic and forward MRPs sufficiently balances and moderates the unsupported assumption that higher analyst expectations over the next five years are expected to continue in the future with the actual achieved MRPs over a long history. As a result, the Panel rejects ICG's submission to only use historical returns and RCIA and the CEC's submission to place greater weight on historical data, along with the related downward adjustment to the CAPM results that they both recommend.

We also reject RCIA's submission that we should use Canadian data only. Investors are free to invest in either the Canadian or US market. In our view, a simple averaging of the two is supportable for this reason and simplifies the estimation process.

5.2.4 Size Premium

Another issue with the CAPM is the size effect, which stems from an observation that smaller firms (where size is measured by market capitalization) tend to have higher returns than predicted by the CAPM.[450] Mr. Coyne notes that the BCUC previously found that the authorized ROE for FBC should be 40 bps higher than that of FEI due, in part, to the small size of FBC.[451] Dr. Lesser explains that to measure size premiums, most analysts rely on the Center for Research in Security Prices (CRSP)'s size premium estimates for 10 groups of market capitalization, published each year by Duff & Phelps.[452] Dr. Lesser typically incorporates a size premium in his analysis.[453]

While Mr. Coyne did not add a size premium to his CAPM ROE results, he nonetheless uses the Duff & Phelps data to calculate the size premium required for FBC. Mr. Coyne explains that his approach is to calculate the difference between the size premium associated with the average or median market capitalization of the US electric proxy group companies and the size premium associated with FBC's market capitalization.[454] Since the median market capitalization of the companies in his US electric proxy group falls in the second decile and that of FBC falls in the seventh decile, using the Duff & Phelps table, Mr. Coyne calculates that FBC's small size relative to his US electric proxy group companies would justify a size premium of approximately 105 bps (i.e. 1.54% - 0.49%).[455]

Dr. Lesser commented that Mr. Coyne's approach is without theoretical basis and arbitrary.[456] Rather, Dr. Lesser would adjust the CAPM estimates of each proxy group company by the required size premium so that the CAPM results would include a size adjustment.[457] This is also the methodology used by FERC to calculate the size premium.[458] Mr. Coyne calculates the size premium according to Dr. Lesser or FERC's methodology as 30 bps for the US electric proxy group and 38 bps for the North American electric proxy group.[459]

[450] Exhibit A2-3, p. 55.
[451] Exhibit B1-21, Part 2, p. 28.
[452] Exhibit A2-3, p. 55.
[453] FortisBC Final Argument, p. 177.
[454] Transcript Volume 4, p. 470, Lines 5–8.
[455] Exhibit B1-8-1, Appendix C, p. 5, Transcript Volume 4, p. 464, Lines 7–10.
[456] Transcript Volume 4, p. 471, Lines 7–10.
[457] Ibid., p. 468, Lines 4–23.
[458] Exhibit B1-50, p. 1.
[459] Ibid., Figures 14 and 16, pp. 11–12.

FortisBC submits that the experts agree that the CAPM underestimates the cost of equity for smaller companies and that the BCUC should find that Mr. Coyne's CAPM results for FBC are understated[460] and should consider a size premium for FBC, which is much smaller than the electric proxy group companies.[461] FortisBC notes that the BCUC has previously found, exercising a judgment-based approach, that the authorized ROE for FBC should be 40 bps higher than that of FEI due, in part, to the small size of FBC. This is smaller than what the Duff & Phelps table would indicate.[462] In short, FortisBC submits that the BCUC should find that Mr. Coyne's CAPM results for FBC are very conservative by virtue of not including a size premium of 105 bps, or alternatively, a minimum of 40 bps.[463]

Positions of Parties

<u>BCOAPO</u>

BCOAPO cites Mr. Coyne and Dr. Lesser who both acknowledge a "size effect" and notes that, while Mr. Coyne has not included a size adjustment in his ROE recommendations for FBC, he nonetheless calculates a size premium of 105 bps would be justified relative to the US electric proxy group companies.[464]BCOAPO surmises that similar results would likely apply to the revised North American electric proxy group which is made up largely of utilities from the US electric proxy group.[465]

BCOAPO submits that it would be reasonable for the BCUC to recognize the implications of this size difference on FBC's CAPM results. BCOAPO submits that in order to help recognize both the financial leverage difference between FBC and the North American electric proxy group and the implications that size difference has on the CAPM results, it would be reasonable for the BCUC to set the authorized ROE for FBC at 9.50 percent (as opposed to 9.01 percent), assuming a 50 bps allowance for floatation costs.[466]

<u>The CEC</u>

The CEC notes that both experts agree that CAPM underestimates the cost of equity for smaller companies leading to a size premium adjustment for FBC. The CEC remarks that the BCUC has previously set the size premium for FBC at 40 bps higher than FEI, which is smaller than the Duff & Phelps table of size premiums would indicate. FortisBC suggests that Mr. Coyne's recommendations should be viewed as conservative. The CEC submits maintaining the FBC 40-bps adder continues to be appropriate and any further movement on the size premium is not necessary.[467]

<u>FortisBC Reply Argument</u>

FortisBC notes that, while BCOAPO acknowledges the need for a size premium for FBC, it recommends an amount far less than the 105 bps calculated by Mr. Coyne based on Duff & Phelps. FortisBC states that

[460] FortisBC Final Argument, para. 359, p. 177.
[461] Ibid., para. 244(f), p. 122.
[462] Ibid., para. 364, p. 179.
[463] Ibid., para. 365, p. 180.
[464] BCOAPO Final Argument, p. 55.
[465] Ibid.
[466] Ibid., p. 58.
[467] The CEC Final Argument, pp. 55–56.

BCOAPO's own calculations suggest an implicit size premium of 46 bps, but when considering a mathematical error made by BCOAPO, the implicit size premium is reduced to 21 bps.[468]

Panel Determination

Both experts agree that smaller firms tend to have higher returns than predicted by application of the CAPM. We also note that Mr. Coyne does not propose to adjust his FBC CAPM results to reflect a size premium. However, we note that FortisBC submits that the BCUC should find that Mr. Coyne's CAPM results for FBC are understated by a minimum of 40 bps and should consider a size premium for FBC, which is much smaller than the electric proxy group companies. The Panel will review the implications of the lack of a size premium in making its overall determination on the capital structure and ROE for FBC in Section 6.3 (Overall Capital Structure and ROE).

5.2.5 Overall CAPM Results

In Section 5.2.1, the Panel finds that Mr. Coyne's estimated risk-free rate based on forecast long-term government bond yields for his CAPM estimate is reasonable. In Section 5.2.2, the Panel accepts Mr. Coyne's beta estimates for the proxy groups. In Section 5.2.3, the Panel concludes it can place little weight on the two-stage forward-looking MRP model derived by Mr. Coyne based on his interpretation of Dr. Lesser's preferred approach. Accordingly, this section reviews Mr. Coyne's October 2022 proposed CAPM ROE and intervener submissions regarding these results.

Consistent with the Panel's earlier determination to use the most current data, the table below summarizes Mr. Coyne's CAPM results based on the October 2022 data.

Table 16: CAPM ROE Results (excluding floatation costs)[469]

October 2022	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
Mr. Coyne	9.62%	9.46%	9.80%	10.01%	9.74%

Mr. Coyne's results reflect his approach of using a forecast bond yield for the risk-free rate, Blume-adjusted betas, and an MRP which consists of the average of Canadian and US historical and forward-looking MRPs with the latter derived using a constant DCF model. His results do not include a Hamada adjustment to account for the difference in leverage between the utilities under review and the proxy group companies.

FortisBC submits that the anomalous CAPM results produced by Mr. Coyne using his interpretation of Dr. Lesser's preferred inputs serve as a reminder of the importance of the BCUC considering models holistically, rather than making discrete decisions on model elements or inputs in a vacuum. FortisBC emphasizes that for every modelling decision that Mr. Coyne made that participants have challenged because it directionally produced higher ROE results, there are examples where Mr. Coyne made decisions that had the opposite effect:

[468] FortisBC Reply Argument, p. 47.
[469] Exhibit B1-50, Table 3, Scenario A.2, p. 4.

- Did not add a Hamada adjustment to his CAPM modelling to account for the fact that FBC and FEI are both more highly leveraged than the proxy group companies. This was predicated on the common equity ratio proposal that would reduce the disparity between the allowed equity ratio for FEI with the proxy groups and retaining FBC's existing equity ratio;
- Did not add a 105-bps size premium to his CAPM results for FBC, despite both experts believing a ROE size premium is appropriate;
- Recommended forecast bond yields rather than actual bond yields, even though the former produces lower CAPM results based on October 2022 data; and
- Averaged the forward-looking MRP with the lower historical MRP to moderate the results, despite it also being theoretically valid to only use a forward-looking MRP (as does FERC).[470]

FortisBC cautions that "assessing each of Mr. Coyne's methodological decisions in isolation risks "cherry picking", producing a result that poorly reflects current market conditions and the forward-looking expectations of investors.[471]

Positions of Parties

<u>ICG</u>

ICG's final argument is submitted on behalf of FBC's industrial customers and therefore, it is focused on issues of relevance to FBC only.[472] ICG submits that the BCUC should give no weight to Mr. Coyne's CAPM results and that the BCUC should reject FortisBC's submission to not place any weight on the Lesser CAPM results.[473] Despite Mr. Coyne's testimony that the model inputs recommended by Dr. Lesser somehow affected the Concentric model to the point of affecting the functionality of the model, ICG submits that the BCUC should dismiss this notion and can rely on the model results once it has determined the appropriate inputs to the model.[474]

Regarding the recommended ROE for FBC, ICG submits:[475]

> Dr. Lesser's Average CAPM and Multi-Stage [sic] DCF results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates) is 8.3% ROE.[36]
>
> Footnote 36: Exhibit B1-50, p. 9, Figure 10

Based on ICG's overall ROE recommendation above, it is possible to separately identify ICG's recommended CAPM ROE. In the main body of ICG's submission, ICG references, "Dr. Lesser's […] CAPM results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates)". This specific scenario results in an ROE of 7.60 percent.[476] However, the text in footnote 36 references a different

[470] FortisBC Final Argument, para. 265, pp. 133–134.
[471] FortisBC Final Argument, para. 266, p. 134.
[472] ICG Final Argument, p. 3.
[473] Ibid.
[474] Ibid., p. 10.
[475] Ibid., para. 33, p. 15.
[476] Exhibit B1-50, Scenario B.6, Figure 12, p. 10.

scenario, that of Dr. Lesser's December 2021 data (90-day average stock prices and interest rates). This scenario results in an ROE of 7.50 percent.[477]

Therefore, before the flotation allowance adder, ICG recommends a CAPM ROE of 7.00 or 7.10 percent for FBC, depending on the scenario one looks at (October 2022 – 30 days versus December 2021 – 90 days) based on the North American proxy group.

BCOAPO

As previously explained in Section 3.2, BCOAPO modifies the composition of the North American proxy group. BCOAPO recalculates revised CAPM ROE estimates by removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group and Canadian Utilities Limited from the North American electric proxy group, as these utilities would not pass Mr. Coyne's screening criteria.[478] BCOAPO then averages its own recalculated Coyne – CAPM and Lesser – CAPM to derive its CAPM ROE results, shown in Table 17 below.

Table 17: BCOAPO - Summary of CAPM ROE – October 2022 (90 Trading Days)[479]

Average CAPM Results (*i.e.* average of historic and forward-looking MRP) * Results include the 50-bps flotation costs			
BCOAPO-Revised Proxy Group	Coyne-Average CAPM as revised by BCOAPO	Lesser-Average CAPM *as revised by BCOAPO*	BCOAPO recommended CAPM
North American Gas Utilities	10.40%	8.86%	**9.63%**
North American Electric Utilities	10.27%	8.75%	**9.01%**

Since the above figures already include a 50-bps adder for flotation costs and financial flexibility, Table 18 shows the results without the adder.

Table 18: BCOAPO - Summary of CAPM ROE – October 2022 (90 Trading Days)[480]

Average CAPM Results (*i.e.* average of historic and forward-looking MRP) * Results exclude the 50-bps flotation costs			
BCOAPO-Revised Proxy Group	Coyne-Average CAPM as revised by BCOAPO	Lesser-Average CAPM *as revised by BCOAPO*	BCOAPO recommended CAPM
North American Gas Utilities	9.90%	8.36%	**9.13%**
North American Electric Utilities	9.77%	8.25%	**8.51%**

The CEC

The CEC submits that the BCUC should give significant weight to Mr. Coyne's CAPM and not use the CAPM results based on Mr. Coyne's interpretation of Dr. Lesser's approach in its determinations. The CEC states there

[477] Exhibit B1-50, Scenario B.6, Figure 10, p. 9.
[478] BCOAPO Final Argument, pp. 52–53.
[479] Ibid.
[480] Table created from Table 17 figures with 50 bps subtracted.

are questionable assumptions, and the results are too far away from a reasonable level as noted even by Dr. Lesser. Additionally, the CEC is satisfied that the differences between the two CAPM models have been explained and that they do not arise from model flaws but from differences in input data used and/or the specific selected treatment of the input data.[481]

The CEC uses Mr. Coyne's CAPM results (October 2022, 90 days) to derive its own ROE recommendation. The CEC recommends that the BCUC use the simple average of proxy groups to determine the appropriate ROE for FEI and FBC. Before adjustments, the CEC calculates an ROE of 10.127 percent for FEI and 10.29 percent for FBC as shown in Table 19.

Table 19: CEC's Recommended ROE from the CAPM (including flotation costs)[482]

	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	10.12%	9.96%	10.30%	10.127%
Electric	10.12%	10.51%	10.24%	10.29%

Since the above figures already include a 50-bps adder for flotation costs and financial flexibility, Table 20 shows the results without the adder.

Table 20: CEC's Recommended ROE from the CAPM (excluding flotation costs)[483]

	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	9.62%	9.46%	9.80%	9.627%
Electric	9.62%	10.01%	9.74%	9.79%

In conclusion, the CEC recommends that the BCUC acknowledge Mr. Coyne's decisions to adopt reasonably conservative positions on several issues and recommends that the BCUC also adopt a conservative approach.[484]

<u>RCIA</u>

RCIA remarks that Mr. Coyne's CAPM ROE estimates are higher than those obtained from Dr. Lesser's assumptions. As noted above, RCIA is particularly concerned with the parameters proposed in relation to the risk-free rate and the MRP.[485] Considering its specific submissions on those two inputs, RCIA recommends adjusting Mr. Coyne's CAPM. Using the mid-point of these adjustments, the result is an overall decrease of about 2.42 percent in the ROE as shown in Table 21. RCIA submits that the CAPM ROE should be 8.26 percent, not 10.68 percent, as suggested by Concentric.[486]

[481] The CEC Final Argument, pp. 37–38.
[482] Information in the table has been compiled from the CEC Final Argument, p. 43.
[483] Table created from Table 19 figures with 50 bps subtracted.
[484] The CEC Final Argument, p. 42.
[485] RCIA Final Argument, pp. 10–11.
[486] Ibid., p. 20.

Table 21: RCIA - Adjustment to Recommended ROE using CAPM

Correction	Impact on ROE	Mid-Point
Using actual bond yields for risk-free rate	-0.68% to -1.04%	-0.86%
Using only Canadian MRP data	-0.77%	-0.77%
Using 75:25 blend of historical & forecast MRP	-0.79%	-0.79%
Total	**-2.24 to -2.60%**	**-2.42 %**

<u>FortisBC Reply Argument</u>

Regarding ICG's recommendation to use the CAPM results using Dr. Lesser's approach, FortisBC submits:

- This CAPM result that ICG is using in its calculation is 7.10 percent (or 7.60 percent after inclusion of flotation cost), which is a number well below what even Dr. Lesser considers reasonable and not far removed from the cost of debt; and
- ICG did not account for any size premium for FBC, even though the experts agree that the CAPM understates ROE results for firms like FBC that are smaller than the proxy companies.[487]

FortisBC also points out the straightforward mathematical error that BCOAPO made in averaging the results of its CAPM calculations for its adjusted North American proxy group.

FortisBC submits that RCIA introduces unsupported CAPM adjustments, uses stale data, and omits Hamada and size adjustments. For illustration purposes only, FortisBC proceeds to apply RCIA's above downward adjustments to the October 2022 data, since both experts note the appropriateness of using the most recent data and RCIA did not say why it disregarded that data. Mr. Coyne's October 2022 CAPM results for the Canadian proxy group is 10.12= percent. [488] Using actual bond yields will increase CAPM results by 6 to 42 bps with a mid-point of 24 bps while using 75:25 Canadian-only historical and forward-looking MRP will decrease the October 2022 CAPM results by 93 bps. Overall, the downward adjustment would be 69 bps on 10.12 percent (=9.43%[489]), instead of the -2.42 percent on 10.68 percent (=8.26%).[490] FortisBC submits that RCIA's own calculations, properly updated for October 2022 data reinforce Mr. Coyne's recommendations, which is a full answer to RCIA's argument that Mr. Coyne's analysis is biased.[491]

Panel Determination

With respect to the CAPM results, previously in this Decision, the Panel determined that:

- Using the most up-to-date data (i.e. October 2022 data) is appropriate;

[487] FortisBC Reply Argument, pp. 55–56.
[488] Including a 50-bps adder for flotation cost and financial flexibility.
[489] Including a 50-bps adder for flotation cost and financial flexibility.
[490] FortisBC Reply Argument, p. 50.
[491] Ibid., p. 53.

- Mr. Coyne's October 2022 estimated risk-free rate based on forecast long-term government bond yields for his CAPM estimate is reasonable;
- Mr. Coyne's sources and averaging of adjusted data to estimate betas for the proxy groups are acceptable;
- Mr. Coyne's approach to addressing the differences in financial leverage in the proxy group companies through adjustments to the capital structure is acceptable and consistent with how the BCUC typically accounts for relative risk;
- Mr. Coyne's 50:50 weighting of historic and forward MRPs is an appropriate and sufficient balance between the assumption that higher analyst expectations over the next five years are expected to continue into the future and the actual achieved MRPs over a long history; and
- We place no reliance on the two-stage MRP estimate prepared by Mr. Coyne based on his interpretation of Dr. Lesser's preferred approach.

Since we are not relying on the CAPM results based on Mr. Coyne's interpretation of Dr. Lesser's approach, we agree with FortisBC that we should not be adjusting the CAPM results in the manner suggested by BCOAPO. For the same reason, we also disregard ICG's CAPM submissions. Given the Panel determines that it should be using the October 2022 data to inform the establishment of an appropriate ROE, we agree with FortisBC's comments related to RCIA's use of "stale data". Regarding RCIA's suggestion to use a 75:25 blend of historic and forecast MRP, we note our determination that a 50:50 weighting strikes an appropriate balance. However, for reasons previously expressed, we disagree with FortisBC's characterization that the use of historical data as being conservative. As previously noted, the Panel will consider the implications of the lack of a size adjustment in the CAPM results in determining the specific weight to be accorded the various ROE models in Section 6.3 (Overall Capital Structure and ROE).

In Section 3.2 above, the Panel determines that the appropriate proxy groups to use for FEI and FBC are the North American gas and electric proxy groups, which should be revised in accordance with BCOAPO's proposal to remove Enbridge Inc. and Canadian Utilities Limited which are unlikely to have passed Mr. Coyne's screening criteria if applied strictly.

Table 22 shows the detail of Mr. Coyne's North American gas proxy groups CAPM results. Removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group yields a revised calculated average ROE of 9.90 percent compared to the 9.80 percent proposed by Mr. Coyne,[492] excluding an adder for flotation costs and financial flexibility.

[492] Calculated by the BCUC using the Average function in Excel = Average (11.69%,10.03%,9.05%,9.39%,9.35%) = 9.90%.

Table 22: CAPM - North American Gas Utilities[493]

North American Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
AltaGas Inc.	ALA	1.16	n/a	1.16	3.21%	7.29%	11.69%	0.50%	12.19%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.21%	7.29%	9.37%	0.50%	9.87%
Enbridge Inc.	ENB	0.93	0.85	0.89	3.21%	7.29%	9.72%	0.50%	10.22%
New Jersey Natural Resources	NJR	0.84	0.95	0.90	3.50%	7.29%	10.03%	0.50%	10.53%
Northwest Natural Gas Company	NWN	0.72	0.80	0.76	3.50%	7.29%	9.05%	0.50%	9.55%
ONE Gas, Inc.	OGS	0.82	0.80	0.81	3.50%	7.29%	9.39%	0.50%	9.89%
Spire, Inc.	SR	0.81	0.80	0.80	3.50%	7.29%	9.35%	0.50%	9.85%
MEAN		0.88	0.84	0.88			9.80%		10.30%

Table 23 shows the detail of Mr. Coyne's North American electric proxy groups CAPM results. Removing Canadian Utilities Limited from the North American electric proxy group yields a revised calculated average ROE of 9.77 percent compared to the 9.74 percent proposed by Mr. Coyne,[494] excluding any adjustment for a size premium and an adder for flotation costs and financial flexibility.

Table 23: CAPM - North American Electric Utilities[495]

North American Proxy Group	Ticker	Bloomberg	Value Line	Average Beta	Risk Free Rate	Average Market Risk Premium	Basic CAPM Calculation	Flotation Cost	Total CAPM
Algonquin Power and Utilities	AQN	0.99	n/a	0.99	3.21%	7.29%	10.46%	0.50%	10.96%
Canadian Utilities Limited	CU	0.84	n/a	0.84	3.21%	7.29%	9.37%	0.50%	9.87%
Emera Inc.	EMA	0.69	0.75	0.72	3.21%	7.29%	8.45%	0.50%	8.95%
Hydro One, Ltd.	H	0.66	n/a	0.66	3.21%	7.29%	8.03%	0.50%	8.53%
Alliant Energy Corporation	LNT	0.86	0.85	0.85	3.50%	7.29%	9.72%	0.50%	10.22%
American Electric Power Company, Inc.	AEP	0.82	0.75	0.79	3.50%	7.29%	9.23%	0.50%	9.73%
Duke Energy Corporation	DUK	0.80	0.85	0.82	3.50%	7.29%	9.50%	0.50%	10.00%
Entergy Corporation	ETR	0.94	0.95	0.94	3.50%	7.29%	10.39%	0.50%	10.89%
Exelon Corporation	EXC	0.95	NMF	0.95	3.50%	7.29%	10.42%	0.50%	10.92%
Evergy Inc	EVRG	0.87	0.90	0.89	3.50%	7.29%	9.96%	0.50%	10.46%
NextEra Energy Inc.	NEE	0.89	0.95	0.92	3.50%	7.29%	10.19%	0.50%	10.69%
OGE Energy Corporation	OGE	0.99	1.05	1.02	3.50%	7.29%	10.94%	0.50%	11.44%
Pinnacle West Capital Corporation	PNW	0.90	0.90	0.90	3.50%	7.29%	10.07%	0.50%	10.57%
Portland General Electric Company	POR	0.84	0.85	0.84	3.50%	7.29%	9.65%	0.50%	10.15%
MEAN		0.86	0.88	0.87			9.74%		10.24%

Therefore, the Panel will consider a CAPM ROE, exclusive of an adder for flotation costs and financial flexibility of 9.90 percent for FEI and 9.77 percent for FBC as it weights the different ROE models (see Section 6.3).

5.3 Discounted Cash Flow Approach

The premise underlying the DCF model is that investors value a given investment according to the present value of its expected cash flows over time. The standard DCF model is shown in Equation (3):[496]

$$P = \frac{D_0(1+g)^1}{(1+r)^1} + \frac{D_1(1+g)^2}{(1+r)^2} + \cdots + \frac{D_{n-1}(1+g)^n}{(1+r)^n} \qquad (3)$$

Where:

P = the current stock price

g = the dividend growth rate

Dn = the dividend in year n

r = the cost of common equity

493 Exhibit B1-50, Attachment A.2 FEI – Gas (Oct 2022 update 90 day), Tab JMC-FEI-6.1 Avg CAPM.

494 Calculated by the BCUC by averaging the following figures: 10.46%, 8.45%, 8.03%, 9.72%, 9.23%, 9.50%, 10.39%, 10.42%, 9.96%, 10.19%, 10.94%, 10.07% and 9.65%.

495 Exhibit B1-50, Attachment A.2 FBC – Electric (Oct 2022 update 90 day), Tab JMC-FBC-8.1 Avg CAPM.

496 Exhibit B1-8-1, Appendix C, p. 48.

Applying the DCF methodology to solve Equation (3) for the cost of equity, *r*, one can determine the discount rate that equates the discounted present value of those future dividend payments to the stock's price today. Thus, the DCF methodology can be thought of as a stock valuation exercise in reverse. Assuming a constant growth rate in dividends, the equation can be rearranged to compute the ROE as shown in Equation (4):[497]

$$r = \frac{D}{P} + g \qquad (4)$$

Stated otherwise, the cost of equity is equal to the dividend yield (D/P) plus the expected dividend growth rate.[498] This DCF model, known as the Constant Growth DCF Model, requires several assumptions: (1) a constant average growth rate for dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

Dr. Lesser states that the advantage of the Constant Growth DCF model is its simplicity; however, this simplicity is also a disadvantage of the model because it assumes that short-term growth rates continue forever.[499] An alternative to the Constant Growth DCF model is the Multi-Stage DCF model, which tempers the assumption of constant dividend growth in perpetuity with a multi-stage dividend growth rate. Dr. Lesser states that "the rationale for using a multi-stage DCF model is that high short-term growth rates cannot persist forever. As firms increase in size, their markets become saturated, and thus their growth slows."[500] The Multi-Stage DCF model was the BCUC's preferred DCF model in the last two cost of capital proceedings.[501] Even though Mr. Coyne presents the results of the Constant Growth DCF model, he recommends the use of a multi-stage DCF model that employs three stages for dividend growth; near-term, transitional, and long-term growth rates (see Section 5.3.2). Dr. Lesser also confirms his preference for a Multi-Stage DCF model over Constant Growth DCF because long-term earnings growth reverts to that of the economy as a whole.[502] Dr. Lesser discusses the merits of both a two-stage and a three-stage dividend growth rate model, without stating a preference.

Dr. Lesser explains that, like the CAPM, the DCF model will mis-estimate the cost of capital for a utility when there is a mismatch between the common equity ratio of the subject utility and the common equity ratios of the peer group used:[503]

> When setting an allowed ROE value for a regulated utility, the resulting WACC [weighted average cost of capital] value may not reflect risk comparability if the capital structure of the regulated utility under review differs from those of the proxy group. For example, if the average capital structure of the proxy group is 50% equity and 50% debt, while the subject utility has a capital structure of 25% equity and 75% debt, then because the subject utility has more financial risk, equity investors will require a higher expected return.

FortisBC points out that Mr. Coyne "[d]id not perform a WACC adjustment to the Multi-Stage DCF results […] to account for the fact that FBC and FEI are both more highly leveraged than the proxy group companies. This was

[497] Exhibit B1-8-1, Appendix C, p. 48.
[498] Ibid.
[499] Exhibit A2-3, p. 30.
[500] Ibid., p. 29.
[501] Exhibit B1-8-1, Appendix C, pp. 52–53.
[502] Exhibit A2-5, BCOAPO IR 3.1.
[503] FEI Final Argument, p. 174.

predicated on the common equity ratio proposal that would reduce the disparity between the allowed equity ratio for FEI with the proxy groups and retaining FBC's existing equity ratio."[504]

The following sub-sections discuss the determination of the dividend yield and the dividend growth rate.

5.3.1 Dividend Yield

The first term in Equation (4) is the dividend yield, which has two key drivers. The first driver is the selection of the proxy group, and the second is the historic time period used to gather stock prices data for the respective companies in the proxy group. Mr. Coyne calculates the dividend yields for each company in his five proxy groups[505] by dividing the current annualized dividend by the average stock price for each company. Those dividend yields are multiplied by one-half the dividend growth rate to account for increases in quarterly dividends at different times throughout the year as shown in Equation (5).[506] Dr. Lesser also supports adjusting the current dividend yield by 0.5 times the growth rate.[507]

$$Y = \frac{D}{P} = \frac{D_0(1 + 0.5g)}{P_0} \qquad (5)$$

Mr. Coyne uses a 90-trading day average for stock prices to calculate the dividend yield for proxy group firms in both his December 2021 evidence and his September 2022 Update. The latter resulted in lower Multi-Stage DCF results across the board relative to the former.[508] Reflecting on these results, Concentric states:

> Under normal market circumstances, Mr. Coyne would accept these results as determinative, but substantially higher interest rates and sustained higher inflation levels do not indicate a reduction in the cost of equity -- this is not an intuitive result. Markets have been anything but normal in 2022. […] Contributing to this capital market turmoil, inflation in both the US and Canada is running at levels not seen since the early 1980s. In previous periods of market disruption, utilities have served as a safe haven for investors, but as explained in a *Wall Street Journal* article this week, that has not been the case recently.[509] [*Emphasis added*]

The *Wall Street Journal* article explains that, while utility stocks were among the best-performing segment of the market in the early part of 2022, they became the worst-performing sector of the S&P 500 in the period mid-September 2022 to mid-October 2022, as the sizable dividends of utility stocks (among the highest payout percentages in the index at 3.3 percent) were no match for climbing bond yields reaching four percent in mid-October 2022.[510]

Mr. Coyne explains that these market circumstances require an examination of the models and inputs used for estimating the cost of capital and the application of informed judgment. With respect to the DCF model, Mr. Coyne expresses the following concern:

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504 FEI Final Argument, p. 134.

505 Canadian utilities, US gas utilities, US electric utilities, North American gas utilities, and North American electric utilities.

506 Exhibit B1-8-1, Appendix C, p. 49.

507 Exhibit A2-3, p. 27.

508 Exhibit B1-8-1, Appendix C, p. 49, Exhibit B1-8-1-2, Footnote 1, p. 2, FortisBC Final Argument, para. 303, pp. 150–151.

509 Exhibit B1-8-1-2, p. 4.

510 Ibid., pp. 4–5.

> Utility stock prices, as indicated in the above article, have responded slowly to the down market in 2022, so the 90-day historic stock price averages used in the DCF model are not reflective of current market conditions.[511] [*Emphasis added*]

To test this hypothesis, Mr. Coyne replaced the 90-trading day average stock prices with the current stock prices (Spot Price) in his September 2022 Update and when doing so, the Multi-Stage DCF Model results shift back to those estimated in December 2021.[512]

While both experts agree with the use of recent average stock prices in calculating the dividend yield in the DCF Model[513], an area of debate emerged at the oral hearing regarding the appropriate period to use for this exercise in the current economic context. At the oral hearing, Dr. Lesser acknowledged that he may use shorter periods depending on "what's happened in the market", though not shorter than 30 days.[514] FortisBC states that this is consistent with what Dr. Lesser had done in two proceedings from 2002 (he used 30 days in one and 60 days in the other) in circumstances that he had characterized as being influenced by the threat of war, emerging from challenging economic circumstances and unprecedented monetary policy intervention. FortisBC argues that the extraordinary conditions earlier in 2022 are not dissimilar to the conditions highlighted by Dr. Lesser in 2002 and they, too, give rise to concerns that older data are not reflective of investors' forward-looking expectations.[515]

5.3.2 Dividend Growth Rates

The second term (*g*) of Equation (4)[516] is the dividend growth rate, which has two key attributes. The first attribute is the number and duration of the stages of growth, and the second is the basis of the dividend growth for each stage.

5.3.2.1 Number and Duration of the Stages of Growth

Mr. Coyne adopts a three-stage DCF model that employs the following values for the duration and the basis of the dividend growth for each stage:

a) First stage (Years 1 to 5): Near-term growth as measured by analysts' EPS growth projections used in the Constant Growth DCF Model;

b) Second (transitional) stage (Years 6 to 10): Connects near-term with long-term growth by changing the growth rate each year on a pro rata basis; and

c) Third (perpetuity) stage (Years 11 and beyond): Long-term forecast of nominal GDP growth, which is estimated based on estimates of real GDP growth rate and inflation by *Consensus Economics*.[517]

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[511] Exhibit B1-8-1-2, p. 5.
[512] Ibid., p. 6.
[513] Transcript Volume 3, p. 161, Lines 2–4.
[514] Transcript Volume 4, p. 440, Lines 20–24.
[515] FortisBC Final Argument, para 305, p. 151.
[516] Equation (4) is a simplified equation where the dividend growth rate is constant. In a Multi-Stage DCF, the dividend growth rate takes different values for the different stages used in the model.
[517] Exhibit B1-8-1, Appendix C, p. 53.

Dr. Lesser supports Mr. Coyne's approach: "[f]or a multi-stage DCF model, I agree with Mr. Coyne that the most typical approach is to assume an initial stage lasting five years. […] Mr. Coyne's three-stage model is certainly one approach that is sometimes used, and a five-year middle stage is not unreasonable."[518]

5.3.2.2 Basis of the Dividend Growth for Each Stage

<u>Analysts' forecasts in First Stage</u>

In considering the appropriate basis for the growth rate for the first stage in the Multi-Stage DCF model, the most relied upon indicator of investors' expectations is analysts' estimates of future earnings growth. Mr. Coyne explains that investors rely on projected earnings growth rate rather than dividend growth rates because 1) a company's dividend growth is derived and can only be sustained by earnings growth; 2) earnings growth rates are less influenced by dividend decisions; and 3) analysts' forecast of earnings growth are more widely available than dividend forecasts.[519]

Echoing point 1 above, Dr. Lesser states that "because earnings are the ultimate source of dividends – a firm cannot continue to pay dividends if it has no earnings – the growth rate term *g* used in [Equation (4)] is almost always the forecast growth in earnings."[520] Thus, the two experts agree that dividend growth rates should be estimated using earnings growth rates.

Mr. Coyne and Dr. Lesser also agree that analysts' estimates are the appropriate source for forecast earnings growth rates but disagree on which data sources to use for the first stage. Earnings growth rates are forecast by stock analysts typically for periods of three to five years but how those analysts develop their forecasts is not publicly known.[521] Mr. Coyne relies on earnings growth estimates from four data sources: SNL Financial, Value Line, Zacks and Thomson First Call for the companies in the proxy groups.[522] In contrast, Dr. Lesser supports the use of a single source of earnings growth rate forecasts using the Institutional Brokers' Estimate System (IBES) earnings growth rates published by Yahoo!Finance.

Mr. Coyne explains that Yahoo!Finance, Zacks, and SNL Financial are all consensus forecasts, which means these sources gather consensus of the equity analysts that cover these companies, and then they report out the consensus view from those individual analysts.[523] Mr. Coyne states that "[o]ne benefit of averaging four sources is that you get to mitigate the impact of anyone that will differ from another. And there can be some substantial differences, and I would be very concerned with just using one source."[524] Mr. Coyne further states that the EPS growth rates reported by Yahoo!Finance are not always updated on a regular basis such that they may become stale at times, and Yahoo!Finance does not provide EPS growth rates for every Canadian utility company, so it is necessary to also consider other sources such as Zacks Investment Research, Value Line, and SNL Financial to

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518 Exhibit A2-20, BCUC IR 5.4.
519 Exhibit B1-8-1, Appendix C, pp. 49–50.
520 Exhibit A2-3, p. 27.
521 Ibid., p. 31.
522 Exhibit B1-8-1, Appendix C, p. 49.
523 Transcript Volume 3, p. 314.
524 Ibid., pp. 314–315.

develop a more robust DCF analysis for a Canadian proxy group.[525] However, Mr. Coyne confirms that there is coverage by Yahoo!Finance on the Canadian proxy group and submits that it is not an issue at this time.[526]

Dr. Lesser supports the use of a single source of earnings growth rate forecasts,[527] stating, "I do not consider averaging different earnings growth rates to be reasonable because they do not necessarily reflect the same time periods and forecast duration. Also, I prefer, as does FERC, to rely on the IBES earnings growth rates published by Yahoo!Finance because they are available publicly."[528] Dr. Lesser further states that FERC has expressed concerns about mixing and matching earnings growth rates because 1) the analysts are using different methodologies and different time periods and 2) the analysts are using proprietary growth rates to which no one else can have access to.[529] Dr. Lesser also notes that "simply taking an average as Mr. Coyne suggests, that may be reasonable. But if you're taking an average of say someone's result that's unreasonable, […] you may just be baking in an unreasonable value."[530]

The difference between using a single or multiple data sources for the earnings growth rate forecasts was shown to be immaterial, early in the proceeding, when Mr. Coyne re-ran his Multi-Stage DCF model by replacing his earnings growth rate forecast with Dr. Lesser's recommended earnings growth rate forecast based on the IBES earnings growth rates published by Yahoo!Finance based on December 2021 data. For the US gas proxy group, the Multi-Stage DCF ROE decreased from 9.53 percent[531] to 9.44 percent[532] and for the US electric proxy group, the Multi-Stage DCF ROE increased from 8.82 percent[533] to 8.91 percent[534].

GDP growth rate in Second Stage

As noted above, the second stage is a transitional stage that connects near-term with long-term growth by changing the growth rate each year on a pro rata basis. Thus, the GDP growth rates in this stage are derived mathematically and no parties raised issues with this calculation during the hearing.

GDP growth rate in Third Stage

The experts also disagree on the method to calculate the perpetuity GDP growth rate in Stage 3 of the Multi-Stage DCF model. Mr. Coyne calculates the perpetuity GDP growth rate based on GDP and the Consumer Price Index (CPI). Dr. Lesser disagrees with this calculation method and suggests the proper way to convert real GDP growth rate forecast to a nominal one is to use the GDP implicit price deflator. The difference between the CPI and the GDP implicit price deflator is that the CPI is the consumer price index, so it measures inflation for a market basket of consumer goods, whereas the GDP implicit price deflator measures the overall inflation rate of the entire economy.[535] Dr. Lesser further states that using the CPI will overestimate the ROE but admits that "in

[525] Exhibit B1-21, Part 2, p. 11.
[526] Transcript Volume 3, p. 323.
[527] Exhibit A2-3, p. 32.
[528] Exhibit A2-24, BCOAPO IR 17.2.
[529] Transcript Volume 3, p. 318.
[530] Transcript Volume 3, p. 318.
[531] Exhibit B1-8-1, Appendix C, Figure 1, p. 4 (inclusive of a 50-bps adder).
[532] Exhibit B1-25, BCUC IR 3.1.2, Revised Figure 1 (inclusive of a 50-bps adder).
[533] Exhibit B1-8-1, Appendix C, Figure 2, p. 5 (inclusive of a 50-bps adder).
[534] Exhibit B1-25, BCUC IR 3.1.2, Revised Figure 2 (inclusive of a 50-bps adder).
[535] Transcript Volume 3, pp. 261–262.

terms of all the other inputs to the analyses, that whether it's the CPI or the GDP deflator is probably not going to be the determining factor in setting an allowed ROE".[536]

In response, Mr. Coyne notes that he doesn't disagree with Dr. Lesser and if he was looking at historic data on GDP growth rate, he would use the same method as Dr. Lesser. However, since the GDP growth rate is a forecast, Mr. Coyne submits that he prefers to use forecast inflation data and that he is constrained by the available data, as *Consensus Economics* does not forecast the implicit price deflator.[537]

The evidence on record in this proceeding only includes Multi-Stage DCF ROE results where the perpetuity GDP growth rate is based on the GDP and CPI.

5.3.3 Overall Multi-Stage DCF Model Results

The next two sub-sections will present Mr. Coyne's DCF results based on the most recent October 2022 results, consistent with our determination above in Section 3.3 to use the most recent data.

5.3.3.1 Constant Growth DCF Model

Even though Mr. Coyne uses the results of the Multi-Stage DCF model in his ROE recommendation for FEI and FBC, he also presents the results of the Constant Growth DCF Model. Mr. Coyne's results have been revised to exclude the 50-bps adder for flotation costs and financial flexibility as shown in Table 24 below.

Table 24: Mr. Coyne's Constant Growth DCF ROE Results[538]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022 – 90 trading days[539]	11.48%	9.31%	10.45%	9.17%	9.59%
October 2022 – 30 trading days[540]	11.85%	9.57%	10.72%	9.48%	9.94%

5.3.3.2 Multi-Stage DCF Model

Table 25 below presents Mr. Coyne's Multi-Stage DCF results based on the October 2022 data, using different historic time periods for stock prices to calculate the dividend yields. Those results reflect Mr. Coyne's approach of using four data sources for the earnings growth rates and a perpetuity GDP growth rate based on GDP and CPI. The results have been modified to exclude the 50-bps adder for flotation costs and financial flexibility that Mr. Coyne included in his results.

536 Transcript Volume 3, p. 264.

537 Ibid., p. 262.

538 Information in the table is taken from the referenced footnotes within the table.

539 Exhibit B1-50, Figures 3 and 4, Scenario A.2, p. 6.

540 Ibid., Figures 5 and 6, Scenario A.3, p. 7.

Table 25: Mr. Coyne's Multi-Stage DCF ROE Results[541]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022 – 90 trading days[542]	9.96%	8.44%	9.22%	8.24%	8.61%
October 2022 – 30 trading days[543]	10.43%	8.74%	9.53%	8.60%	9.02%

FortisBC points out that both experts agree on the merits of using the Multi-Stage DCF model.[544] FortisBC also states that it is aligned on the key aspects of the Multi-Stage DCF analysis and that Dr. Lesser's Multi-Stage DCF results are identical to Mr. Coyne's results.[545]

FortisBC also notes that Mr. Coyne presented the results of the Constant Growth DCF model, as it "was developed to estimate the cost of equity for dividend-paying companies in mature industries with steady and predictable growth rates, such as public utilities." FortisBC states that the results of this model tend to exceed the multi-stage DCF results because the EPS growth rates of the proxy companies are not constrained to equal GDP growth after 10 years. FortisBC explains that the experts debate whether a company's EPS can exceed GDP growth forever; however, the data demonstrates that EPS for the proxy utilities have grown faster than GDP for the 2005 to 2019 period. In FortisBC's view, the implication of this evidence for the BCUC is that these two models – the multi-stage DCF and the Constant Growth DCF – are both useful, but imperfect indicators of an estimated range of investors' expected returns. FortisBC submits that Mr. Coyne is being conservative in basing his ultimate recommendations on his Multi-Stage DCF model results, rather than a blend of the two DFC models.[546]

FortisBC remarks that Dr. Lesser had, in past testimony, given equal weight to the two DCF models, despite having the same theoretical reservation about the ability of a company's EPS to grow faster than GDP forever. While he has since changed his approach, FortisBC submits that the logic he had applied still has merit. His stated rationale had related to the benefits of having additional data points in the prevailing conditions, characterized by economic uncertainty, unprecedented actions by central banks and the threat of war abroad, all of which are present today.[547]

Regarding the preferred proxy groups, as noted earlier, FortisBC states that, even though Mr. Coyne developed his initial recommendation based on the results of his US proxy groups, the evidence on the record indicates that it would be appropriate for the BCUC to give primary weight to results based on Mr. Coyne's North American gas and electric proxy groups.

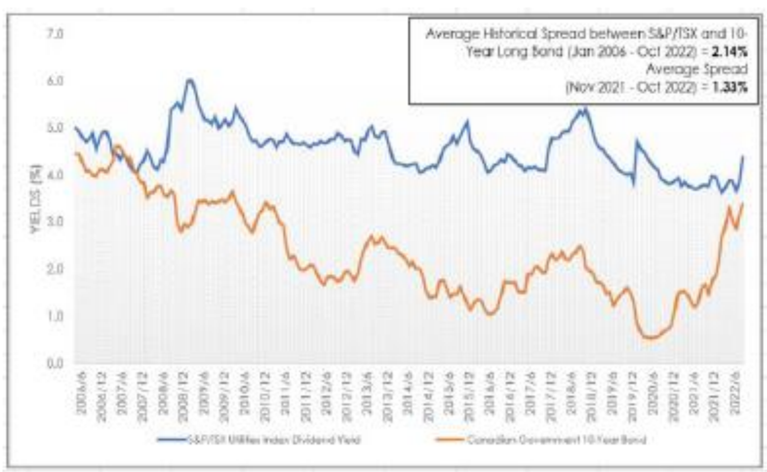
541 Information in the table is taken from the referenced footnotes within the table.
542 Exhibit B1-50, Table 2, Scenario A.2, p. 3.
543 Ibid.
544 FortisBC Final Argument, p. 136.
545 Ibid., p. 122.
546 FortisBC Final Argument, pp. 136–137.
547 Ibid., p. 137.

Dividend Yield

With respect to using 30-day versus 90-day dividend yield data,[548] FortisBC submits that, while using 90-day data is normally reasonable, it may still be skewing the DCF results downwards. While the Efficient Market Hypothesis would suggest current prices are a better indicator of investors' expectations than past data, FortisBC recognizes that both experts agree that it is reasonable to use longer periods as a pragmatic means of moderating daily volatility in stock prices and dividend yields. Nonetheless, FortisBC submits that when interpreting the October 2022 results, the BCUC should consider the 90-day results but also recognize the tendency of a longer period like 90 days to understate investors' expectations due to the lingering effects of extraordinary events earlier in 2022.[549]

To support its position, FortisBC recalls that the six Bank of Canada interest rates increases between January 2022 and the oral hearing, with one more in December 2022, for a total increase of four percent in 2022. As a result, investors' expectations of dividend yields at the end of 2022 would bear little resemblance to what they were prior to the unprecedented increase in interest rates. FortisBC notes that, intuitively, dividend yields on utility stock must be higher than government bond yields to attract investment because utility stocks are higher risk. FortisBC presents a graph showing the statistically significant correlation over time between dividend yields and government bond yields, as shown below, with the notable exception of the summer 2022 when the spread had narrowed. In FortisBC's view, the narrowing spread is evidence that the market took some time to respond to the dramatic change in interest rates and government bond yields.[550]

Figure 2: S&P/TSX Utilities Index Dividend Yield versus Canadian Government 10-Year Bond Yields[551]



Source: Bloomberg series STUTILX and GCAN10YR

FortisBC states that the timing of the September 2022 Update, in conjunction with the use of a 90-trading day period, coincided with the transitory period of suppressed dividend yields and produced much lower results than Mr. Coyne's original analysis based on December 2021 data. FortisBC also notes that Mr. Coyne's October

[548] FortisBC notes that Mr. Coyne refers to "trading days" in his analysis such that "90-day" means 90 trading days and would be slightly more than 4 calendar months.
[549] FortisBC Final Argument, p. 150.
[550] FortisBC Final Argument, pp. 151–153.
[551] Exhibit B1-43; FortisBC Final Argument, p. 153.

2022 Update shows higher results compared to the September 2022 Update.[552] FortisBC cites Mr. Coyne at the oral hearing who noted that "the DCF model is producing results that look more like they did back in December" and that "as you have seen over the course of the last month or so, we've seen them come back into closer alignment. So, it's beginning to correct."[553]

FortisBC references Mr. Coyne's sensitivity analysis to the time horizon used (30-trading days vs. 90-trading days), which shows that a shorter period consistently increases the Multi-Stage DCF results because the lagging data inherent in using a 90-trading day period is still suppressing the DCF results in October 2022. Comparing the 90-day and 30-day scenarios gives an indication that dividend yields were lower in August and September 2022 compared to October 2022 (see Table 25).[554]

FortisBC states that Mr. Coyne confirms that, while the BCUC should have regard to the outputs from December 2021, September 2022, and October 2022, "… at the end of the day I do think that the most current information is what you should probably place the greatest weigh on." However, FortisBC remarks that Mr. Coyne also encourages the BCUC to put the model outputs in context: "So it's been a year of adaptations and disruptions in capital markets. But I think that the point I was making is that you need to understand what's happening to capital markets in 2022 in order to be able to interpret the results we're getting from the models." FortisBC concludes that the BCUC should find that the October 2022 results are potentially understating the investor-required return.[555]

Dividend Growth Rates

Regarding the data sources for EPS growth rates, FortisBC submits that using multiple data sources is a sensible approach and there is a sound logic to relying on multiple data sources, as Mr. Coyne has done, rather than relying on a single source as advocated by Dr. Lesser. Mr. Coyne uses four sources, three of which are consensus forecasts[556] whereas Value Line is an independent analyst forecast. Citing Mr. Coyne, FortisBC states that the purpose of using EPS growth rates in the DCF analysis is to reflect investors' expectations, and investors have access to all these data sources when formulating those expectations. Using multiple forecasts also reduces the potential for anomalous data to influence the results. Finally, Mr. Coyne notes that IBES Yahoo, which Dr. Lesser prefers, had some coverage shortcomings for Canadian companies in the past, as well as times where updates lagged other sources. All these concerns are mitigated by using multiple sources.[557]

Furthermore, FortisBC argues that Dr. Lesser's rationale for sole reliance on IBES does not withstand scrutiny for several reasons. Amongst those, his stance is difficult to reconcile with his support of the Efficient Market Hypothesis, which contemplates that investors will make use of all available information. Also, FortisBC states that Dr. Lesser's concern about different forecast horizons is overstated. Three of the forecasts use a five-year horizon. While Value Line uses three to five years, Mr. Coyne explains that this is not materially different from

[552] FortisBC Final Argument, p. 153.
[553] Ibid., pp. 154.
[554] Ibid., pp. 154–155.
[555] FortisBC Final Argument, p. 155.
[556] Zacks, SNL Financial and Thompson First Call, which is synonymous with IBES and Yahoo.
[557] FortisBC Final Argument, pp. 147–148.

the others in practice and that, in any event, the Value Line estimates "are generally within the range of those other sources".[558]

Positions of Parties

ICG

Regarding the DCF model, ICG only comments on the use of a single versus four sources of information for EPS growth rates. ICG agrees that investors use all sources of information. For practical reasons, ICG submits that using either a single or four sources for such information is not material and both are consistent with the Efficient Market Hypothesis.[559]

Regarding the recommended ROE for FBC, ICG submits:[560]

> Dr. Lesser's Average CAPM and Multi-Stage [sic] DCF results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates) is [sic] 8.3% ROE.[36]
>
> Footnote 36: Exhibit B1-50, p. 9, Figure 10

Based on ICG's above overall ROE recommendation, it is possible to separately identify ICG's recommended Multi-Stage DCF's ROE. In the main body of ICG's submission, ICG references "Dr. Lesser's […] Multi-Stage DCF results for the North American Utilities – Electric with the October 2022 Update (30-day average stock prices and interest rates)". This specific scenario results in an ROE of 9.52 percent.[561] However, the text in footnote 36 references a different scenario, that of Dr. Lesser's December 2021 data (90-day average stock prices and interest rates). This scenario results in an ROE of 9.14 percent.[562]

Therefore, before the flotation allowance adder, ICG recommends a Multi-Stage DCF ROE of 8.64 or 9.02 percent for FBC, depending on the scenario one looks at (October 2022 – 30 days versus December 2021 – 90 days) based on the North American proxy group.

BCOAPO

BCOAPO notes that both experts conclude that the Multi-Stage DCF model should be used for purposes of estimating the ROE.[563]

BCOAPO notes the two experts' general agreement on the appropriate average period to calculate the dividend yield: Mr. Coyne uses a 90-trading day period in both his evidence and the September 2022 Update, and Dr. Lesser advocates for a three- to six-month period with a preference for three months, noting that one month should be the absolute minimum. BCOAPO notes that Mr. Coyne presents results using stock prices determined

[558] FortisBC Final Argument , pp. 148–149.
[559] ICG Final Argument, p. 9.
[560] Ibid., para. 33, p. 15.
[561] Exhibit B1-50, Scenario B.6, Figure 12, p. 10.
[562] Ibid., Scenario B.5, Figure 10, p. 9.
[563] BCOAPO Final Argument, p. 42.

over both 30-trading days and 90-trading days for purposes of an undertaking filed after the oral hearing. BCOAPO remarks that the only difference in the inputs used for the DCF calculations based on a 30- versus 90-day trading basis is the stock prices used in each, which are on average lower in the 30-day calculation in all relevant proxy groups. BCOAPO notes that the annual dividend values growth rates are the same for both periods.[564] BCOAPO agrees with Mr. Coyne's assessment that "[w]e're in an environment where there's a lot of uncertainty about the future of the economy at this point in time in the near term," and with this in mind, BCOAPO submits that DCF calculations based on 90 trading days should be the primary focus of the BCUC's deliberations. BCOAPO adds that this view is further reinforced by the fact that analysts' estimates of earning growth used in the DCF calculation are not necessarily updated every 30 trading days.[565]

With respect to the sources that should be used for the earnings growth rate forecasts, BCOAPO finds the rationale provided by Mr. Coyne in his rebuttal evidence and oral testimony for using multiple earnings growth sources to be compelling and agrees with his approach on this issue.[566]

As explained in more detail in Section 3.2, BCOAPO revises Mr. Coyne's Multi-Stage DCF ROE results by removing the two Canadian utilities that would, in Mr. Coyne's view, not pass the same screening criteria that he used to screen the US firms. BCOAPO's results, from those revisions, are 8.63 percent and 8.57 percent (excluding a 50-bps adder for flotation costs and financial flexibility) for the North American gas and electric proxy groups, respectively. BCOAPO submits that the BCUC should use these revised DCF ROE results when determining FEI and FBC's ROEs.[567]

<u>The CEC</u>

The CEC submits that the BCUC should give significant weight to the Multi-Stage DCF model while not weighting the Constant DCF model into its decision-making but using it only qualitatively in forming its final ROE determinations for FEI and FBC.[568] Regarding the use of 30-day or 90-day data, the CEC notes that both experts agree that a longer period is more appropriate to moderate daily volatility in stock prices and dividend yields. Mr. Coyne has used 90 days (trading days) and Dr. Lesser said he has no objection to the 90 days but would prefer data from one to three months. The CEC submits that the 90-day period for the data is appropriate in the circumstances and the shorter 30-day perspectives can be used as judgement information should the BCUC find it relevant for a particular concern.[569]

Regarding the basis of the dividend growth in the first stage, the CEC notes that both experts agree that projected earning is appropriate for the DCF modelling rather than DPS or sustainable growth, but they disagree on the source of the earnings information, with Mr. Coyne preferring multiple sources and Dr. Lesser preferring a single source. The CEC submits that both Dr. Lesser's approach and Mr. Coyne's approach have merit and the BCUC could make use of them by weighting each of these approaches into the BCUC's judgment as opposed to trying to pick one over the other.[570]

[564] BCOAPO Final Argument, pp. 39–40.
[565] Ibid., p. 40.
[566] Ibid., p.41.
[567] BCOAPO Final Argument, pp. 43–44.
[568] The CEC Final Argument, p. 39.
[569] Ibid., paras. 313–314, p. 45.
[570] Ibid., paras. 311–312, pp. 44–45.

Overall, the CEC recommends that the BCUC gives substantial weight to the multi-stage DCF modelling from Dr. Lesser[571] but proceeds to only highlight key results from Mr. Coyne's updated summary analysis for his October 2022, 90 days average stock prices and interest rates. Before adjustments, the CEC calculates an ROE of 9.71 percent for FEI and 9.81 percent for FBC as shown in Table 26, which is derived based on a simple average of the three proxy groups' results.[572]

Table 26: CEC's Recommended ROE from the Multi-Stage DCF Model[573]

Multi-Stage DCF Model Results for:	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	10.46%	8.94%	9.72%	9.707%
Electric	10.46%	8.74%	9.11%	9.813%

Since the above figures already include a 50-bps adder for flotation costs and financial flexibility, Table 27 shows the results without the adder.

Table 27: CEC's Recommended ROE from the Multi-Stage DCF Model[574]

Multi-Stage DCF Model Results for:	Canadian Regulated Utilities	U.S. Utilities	North American Utilities	Average of Proxy Groups
Gas	9.96%	8.44%	9.22%	9.207%
Electric	9.96%	8.24%	8.61%	9.313%

FortisBC Reply Argument

As BCOAPO, the CEC and ICG all rely on the Multi-Stage DCF model, FortisBC limits its reply to addressing discrete issues about the model's application: a) the averaging period for calculating the dividend yield and b) the number of data sources for the dividend growth rate.[575]

On the first issue, FortisBC reiterates that using 90-trading day dividend yields is reasonable but skews the results downwards. In response to BCOAPO's submission that 90 trading days "should be the primary focus" because of the market uncertainty, FortisBC agrees that 90 days should be the primary focus under normal market conditions, but the BCUC should recognize that a period that long is skewing the DCF results downwards in the current circumstances. FortisBC notes that it is a fact that interest rates increased by 2.25 percent during the 90-day period used for Mr. Coyne's September 2022 Update, plus another 1.25 percent in September and October 2022. Referring to data that FortisBC includes in its final argument (see Figure 2), FortisBC states that statistical data shows that dividend yields on utility stocks are generally higher than government bond yields, which is intuitive, as higher returns are necessary to attract investment with a higher risk profile. As Mr. Coyne explains in his September 22 Update, utility stock prices lagged the sharp interest rate increases and down

571 The CEC Final Argument, para. 296, p. 42.
572 Ibid., paras. 299–300, p. 43.
573 Ibid.
574 Table created from Table 26 figures with 50 bps subtracted.
575 FortisBC Reply Argument, p. 59.

market in 2022, meaning that "90-day historic stock price averages used in the DCF model are not reflective of current market conditions."[576]

On the second issue, FortisBC states that only BCOAPO and the CEC address the source of analyst estimates in the DCF model and points to BCOAPO's agreement to using multiple sources. In response to the CEC's suggestion to give weight to both Mr. Coyne and Dr. Lesser's approaches, FortisBC points out that Dr. Lesser's preferred source (IBES or Yahoo!Finance) is already included as one of Mr. Coyne's sources (i.e. Thompson First Call). Thus, the CEC's approach would give double weight to IBES without a clear reason as to why.[577]

FortisBC also points out that RCIA did not discuss or rely on the Multi-Stage DCF model at all, which FortisBC considers a notable omission and a key reason why its overall recommended ROE is so low. FortisBC submits that RCIA's choice to disregard the Multi-Stage DCF model is untenable because: a) both experts embrace that model, which is based on sound financial theory; b) the DCF methodology is the most commonly used by US regulators; c) the BCUC has generally given significant weight to the Multi-Stage DCF model results; and d) both experts agree on almost all data inputs so that the BCUC can have a particularly high confidence in the results.[578]

Panel Determination

Consistent with the BCUC's preferred approach in the last two cost of capital proceedings, the Panel finds that a Multi-Stage DCF model is preferable to a Constant Growth DCF model. The Multi-Stage DCF model allows for recognition that the proxy utility companies' dividend growth rates may not perform the same in different time horizons.

The Panel accepts that the results from the Multi-Stage DCF model may be more conservative than those from the Constant DCF model, and notes that no interveners favoured the Constant DCF model. Thus, the Panel finds that considerable weight should be given to the use of a Multi-Stage DCF model the purposes of determining the appropriate ROE for FEI and FBC. The specific weight to be accorded the Multi-Stage DCF model in the respective ROEs will be discussed in Section 6.3. (Overall Capital Structure and ROE).

In its final submission, FortisBC states that both Mr. Coyne and Dr. Lesser are aligned on the key aspects of the Multi-Stage DCF analysis, and that the Lesser Multi-Stage DCF results are identical to Mr. Coyne's results. As part of an undertaking after the oral hearing, Mr. Coyne provides four Multi-Stage DCF model runs that he entitles "B.4 to B.7 – Lesser".[579] However, Mr. Coyne was not asked to change any of his Multi-Stage DCF model inputs to replace them with Dr. Lesser's preferred inputs.[580] Thus, three of the four "Lesser" model runs are merely duplicates of Mr. Coyne's model runs for December 2021, October 2022 (90-day) and October 2022 (30-day) and as a result, the model outputs are identical. Therefore, one cannot conclude that Dr. Lesser's Multi-Stage DCF model supports Mr. Coyne's Multi-Stage DCF ROE results, as there are effectively no "Lesser Multi-Stage DCF Results".

[576] FortisBC Reply Argument, pp. 59–60.
[577] Ibid., p. 61.
[578] Ibid., pp. 48–49.
[579] Exhibit B1-50, Table 2, p. 3.
[580] Ibid., p. 1 – see list of requested scenarios.

Having only Mr. Coyne's October 2022 Multi-Stage DCF model results, the Panel must then decide which input to use for the dividend yield (i.e. the number of days for the historic stock price average). With respect to the dividend growth rates, the Panel must first determine the appropriate number and duration of the stages of growth, and then the basis of the dividend growth for each stage.

The Panel previously stated it would rely on the most recent October 2022 data to estimate the cost of equity for FEI and FBC. For the Multi-Stage DCF model, Mr. Coyne presents two sets of October 2022 results: 30-trading days versus 90-trading days. FortisBC submits that using 90-day data may still be skewing the DCF results downwards. Both experts agreed that it is reasonable to use longer periods to moderate daily volatility in stock prices and dividend yields. Accordingly, the Panel considers that, under normal market conditions, using 90-day trading data would be both reasonable and preferable to using 30-day trading data.

However, due to the behavior of utility stocks, which went from amongst the best performing to the worst performing segment of the market at about the same time as the latest October 2022 Update, using a 90-trading-day period, which is equivalent to just over four calendar months, risks skewing the October 2022 Multi-Stage DCF results downwards because it would capture the still elevated utility stock prices from July and August 2022 before they became amongst the worst performing around September/October 2022.

Therefore, considering the extraordinary market conditions of 2022, the Panel is willing to accept the use of a shorter 30-trading-day period for utility stock prices and dividend yields. The Panel is further comforted by Dr. Lesser's acknowledgment that he too may use shorter periods depending on "what's happened in the market," though not shorter than 30 days, an approach he did use in 2002 in circumstances that were described as not dissimilar to today's.

Regarding multi-stage DCF models, there are typically two types of such models: a two-stage and a three-stage DCF model. Mr. Coyne only presents the results of a three-stage multi-stage DCF model, with the first two stages lasting five years each and the third stage being the perpetuity stage. Dr. Lesser appears supportive of this approach when he agreed with Mr. Coyne that "the most typical approach is to assume an initial stage lasting five years" and noted that "Mr. Coyne's three-stage model is certainly one approach that is sometimes used, and a five-year middle stage is not unreasonable."

Due to the structure of the model, a three-stage multi-stage DCF model will yield directionally higher ROE results than a two-stage DCF model because the EPS growth rates are only constrained to equal the lower GDP growth rates in Year 11 as opposed to in Year 6. Recognizing that no interveners commented on the pros and cons of using a two-stage versus a three-stage DCF model and that a majority of them supported the three-stage DCF model presented by Mr. Coyne, the Panel finds it reasonable to use a three-stage DCF model to estimate the ROE for FEI and FBC, with the first two stages lasting five years each.

Next, the Panel must evaluate the reasonableness of the data sources for the dividend growth rates in the first and third stage, where the experts disagree. In the first stage, the Panel considers the use of earnings to be reasonable given that dividends are paid out of earnings. The Panel notes that both experts agree that analysts' estimates are the appropriate source for forecast earnings growth rates but disagree on how many data sources to use for the first stage. Recognizing that these are only analysts' estimates, the Panel finds that using multiple sources for these forecasts is better than using a single source because averaging can mitigate the impact of any one forecast that differs from the others. In any case, a sensitivity analysis performed on the December 2021 data shows that using one or four data sources has less than a 10-bps impact on the Multi-Stage DCF model results.

In the third stage, the Panel finds that using the GDP price deflator would be better than using CPI to derive nominal GDP growth rates because CPI only measures inflation related to a subset of all the goods and services produced in the economy, therefore the GDP price deflator is more representative of the market as a whole. However, the Panel accepts that forecasts of the GDP price deflator are not readily available, whereas forecasts of CPI are readily available. Reluctantly, the Panel accepts the use of CPI as a reasonable forecast to be used in the determination of long-term growth rates. The Panel points out that the use of CPI may result in an ROE that is overestimated, but the Panel accepts Dr. Lesser's submission that this difference will not be determinative in the calculation of the overall ROE.

As for the second (transition) stage, the Panel accepts the methodology employed by Mr. Coyne to transition between the first stage and the third stage growth rates.

Based on the above determinations, the Panel finds that Mr. Coyne's choice of inputs for his Multi-Stage DCF model are reasonable to estimate the cost of equity for FEI and FBC. Specifically, the Panel will rely on the October 2022 results using the 30-day average stock prices, modified to exclude the 50-bps adder for flotation costs and financial flexibility, as shown below:

Table 28: Mr. Coyne's Multi-Stage DCF Model results – October 2022 (30-days)[581]

	Canadian Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022 – 30 trading days[582]	10.43%	8.74%	9.53%	8.60%	9.02%

As discussed in Section 3.2 above, the Panel previously determined that the appropriate proxy groups to use for FEI and FBC are the North American gas and electric proxy groups, albeit revised in accordance with BCOAPO's proposal to remove Enbridge Inc. and Canadian Utilities Limited which are unlikely to have passed Mr. Coyne's screening criteria if applied strictly.

Table 29 below shows the detail of Mr. Coyne's North American gas proxy groups. Removing Enbridge Inc. and Canadian Utilities Limited from the North American gas proxy group yields a revised calculated average ROE of 8.93 percent,[583] excluding an adder for flotation costs and financial flexibility.

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581 Information in the table is compiled from the referenced footnotes within the table.

582 Exhibit B1-50, Table 2, Scenario A.3, p. 3.

583 Calculated by the BCUC using the Average function in Excel = Average (9.67%,8.71%,8.99%,8.12%,9.15%) = 8.93%.

Table 29: 30-Day Multi-Stage DCF - North America Gas Utilities[584]

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
AltaGas Inc.	ALA	$1.06	$26.30	8.63%	7.83%	7.03%	6.23%	5.43%	4.64%	3.84%	9.67%
Canadian Utilities Limited	CU	$1.78	$36.30	4.96%	4.77%	4.58%	4.40%	4.21%	4.02%	3.84%	9.52%
Enbridge Inc.	ENB	$3.44	$51.97	7.08%	6.54%	6.00%	5.46%	4.92%	4.38%	3.84%	12.57%
New Jersery Resources Corporation	NJR	$1.56	$41.51	5.96%	5.66%	5.36%	5.05%	4.75%	4.45%	4.14%	8.71%
Northwest Natural Gas Company	NWN	$1.94	$45.67	4.95%	4.82%	4.68%	4.55%	4.41%	4.28%	4.14%	8.99%
ONE Gas, Inc.	OGS	$2.48	$74.01	5.63%	5.38%	5.13%	4.88%	4.64%	4.39%	4.14%	8.12%
Spire, Inc.	SR	$2.74	$65.69	5.77%	5.50%	5.23%	4.95%	4.68%	4.41%	4.14%	9.15%
MEAN				6.14%	5.78%	5.43%	5.07%	4.72%	4.37%	4.01%	9.53%
Flotation Costs [11]											0.50%
											10.03%

Table 30 below shows the detail of Mr. Coyne's North American electric proxy groups. Removing Canadian Utilities Limited from the North American electric proxy group yields a revised calculated average ROE of 8.99 percent,[585] excluding an adder for flotation costs and financial flexibility.

Table 30: 30-Day Multi-Stage DCF - North American Electric Utilities[586]

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate, Years 1-5	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Algonquin Power and Utilities	AQN	$0.72	$11.13	8.69%	7.88%	7.07%	6.26%	5.45%	4.64%	3.84%	13.19%
Canadian Utilities Limited	CU	$1.78	$36.30	4.96%	4.77%	4.58%	4.40%	4.21%	4.02%	3.84%	9.52%
Emera Inc.	EMA	$2.76	$54.78	6.05%	5.68%	5.31%	4.94%	4.57%	4.21%	3.84%	10.09%
Hydro One, Ltd.	H	$1.12	$33.26	4.23%	4.16%	4.10%	4.03%	3.97%	3.90%	3.84%	7.54%
Alliant Energy Corporation	LNT	$1.71	$52.89	5.93%	5.63%	5.34%	5.04%	4.74%	4.44%	4.14%	8.06%
American Electric Power Company, Inc.	AEP	$3.12	$88.61	6.30%	5.94%	5.58%	5.22%	4.86%	4.50%	4.14%	8.51%
Duke Energy Corporation	DUK	$4.02	$93.46	5.53%	5.30%	5.07%	4.83%	4.60%	4.37%	4.14%	9.23%
Entergy Corporation	ETR	$4.04	$104.62	5.78%	5.51%	5.23%	4.96%	4.69%	4.41%	4.14%	8.78%
Exelon Corporation	EXC	$1.35	$38.40	7.70%	7.11%	6.52%	5.92%	5.33%	4.74%	4.14%	8.90%
Evergy Inc	EVRG	$2.29	$60.14	5.67%	5.41%	5.16%	4.90%	4.65%	4.40%	4.14%	8.68%
NextEra Energy Inc.	NEE	$1.70	$77.73	9.73%	8.80%	7.87%	6.94%	6.01%	5.07%	4.14%	7.51%
OGE Energy Corporation	OGE	$1.66	$36.59	3.35%	3.48%	3.61%	3.75%	3.88%	4.01%	4.14%	8.82%
Pinnacle West Capital Corporation	PNW	$3.46	$65.75	2.20%	2.52%	2.85%	3.17%	3.49%	3.82%	4.14%	9.22%
Portland General Electric Company	POR	$1.81	$45.06	3.38%	3.51%	3.63%	3.76%	3.89%	4.01%	4.14%	8.28%
MEAN				5.68%	5.41%	5.14%	4.87%	4.60%	4.32%	4.05%	9.02%
Flotation Costs [11]											0.50%
											9.52%

Therefore, the Panel will use a multi-stage DCF ROE, exclusive of an adder for flotation costs and financial flexibility, of 8.93 percent for FEI and 8.99 percent for FBC as it weights the results of the different ROE models.

5.4 Risk Premium Model

The Risk Premium Model is based on the premise that, from an investor's perspective, common equity capital is riskier than debt, because debt has a senior claim over a firm's assets. Consequently, equity investors require a greater return (i.e. an equity risk premium or ERP) than would bondholders. Thus, the Risk Premium model estimates the cost of equity as the sum of the ERP and the yield on a particular class of bonds and can be represented by Equation (6):[587]

$$ROE = ERP + Y \qquad (6)$$

Where:
ROE = return on equity
Y = applicable bond yield
ERP = the equity risk premium (*i.e.*, difference between allowed ROE and the 30-year Treasury Yield)

Dr. Lesser notes that although the Risk Premium Model is similar to the CAPM, it is a distinct methodology. Whereas the CAPM addresses systematic (i.e. non-diversifiable) market risk, the Risk Premium Model directly

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584 Exhibit B1-50, Attachment A.3 FEI – Gas (Oct 2022 update 30 day), Tab JMC-FEI-3 Multi-Stage DCF.

585 Calculated by the BCUC by averaging the following figures: 13.19%, 10.09%, 7.54%, 8.06%, 8.51%, 9.23%, 8.78%, 8.90%, 8.68%, 7.51%, 8.82%, 9.22% and 8.28%.

586 Exhibit B1-50, Attachment A.3 FBC – Electric (Oct 2022 update 30 day), Tab JMC-FBC-5 Multi-Stage DCF.

587 Exhibit B1-8-1, Appendix C, pp. 62–63, Exhibit A2-3, p. 60.

incorporates both systematic and unsystematic (diversifiable) risk. Also, the ERP in this model is not the same as the MRP in the CAPM, which is calculated as the difference between the expected future market return and the risk-free rate. Rather than adding a premium on top of the risk-free rate, the Risk Premium Model adds an ERP to the rate on long-term bonds, where the ERP represents the additional expected return by equity investors to compensate them for the additional risk they face relative to bondholders.[588]

Dr. Lesser notes two implementation issues in the application of the Risk Premium Model to a regulated utility:

1. How is the ERP estimated? In Dr. Lesser's view, this is the most crucial implementation issue because the ERP cannot be observed directly. Like the MRP in the CAPM, the ERP can be based on the historical difference between ROEs and bond yields or based on a forward-looking estimate; and
2. What is the appropriate bond yield to use (Current versus forecast? Same yield as for bonds with the same rating as the regulated utility under review?). As discussed in Section 5.2.1, Dr. Lesser is of the view that investor expectations are fully reflected in the current bond yields, under the Efficient Market Hypothesis.[589]

5.4.1 How is the Equity Risk Premium Estimated?

To estimate the relationship between the ERP and interest rates, Mr. Coyne first conducts a regression analysis using Equation (7) below to estimate the intercept and slope terms and relies on historical authorized returns from a large sample of US gas and electric distribution companies,[590] an approach similar to FERC's.[591] Mr. Coyne also explains that the regression analysis is performed on US data only since there aren't enough Canadian ROE decisions to develop a statistically meaningful regression analysis.

$$ERP = a + (b \times Y) \tag{7}$$

Where:
ERP = the equity risk premium (*i.e.*, difference between allowed ROE and the 30-year Treasury Yield)
Y = 30-year Treasury Yield
a = intercept term
b = slope term

The regression results, based on the October 2022 data, are shown in Figure 3 and Figure 4 for US gas and electric distribution companies.[592] The relationship between the ERP and the 30-Year Treasury Yields can therefore be written as follows:

U.S. Gas: $ERP = 0.0851 - 0.5775 \times Y$
U.S. Electric: $ERP = 0.0843 - 0.5432 \times Y$

[588] Exhibit A2-3, p. 60.
[589] Ibid., pp. 61–62.
[590] 700 gas utility company rate cases and 859 electric utility company rate cases in the U.S. from 1992 to 2022.
[591] Exhibit B1-8-1, Appendix C, pp. 63–64.
[592] Exhibit B1-50, Scenario A.2, Gas and Electric Excel spreadsheets, Tab "JMC-FEI 7 Risk Premium".

Figure **3**: Risk Premium Results - U.S. Gas[593]

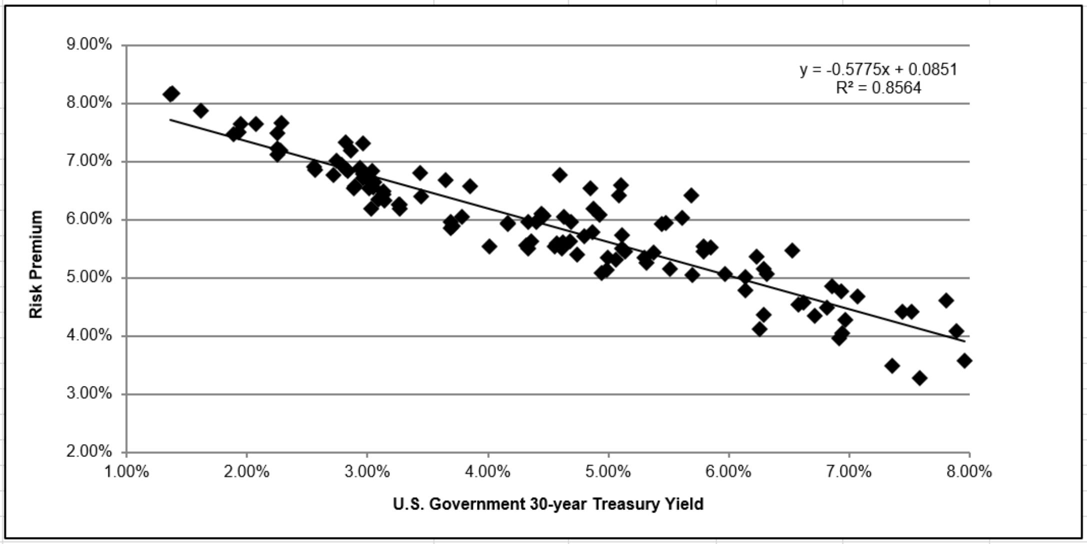
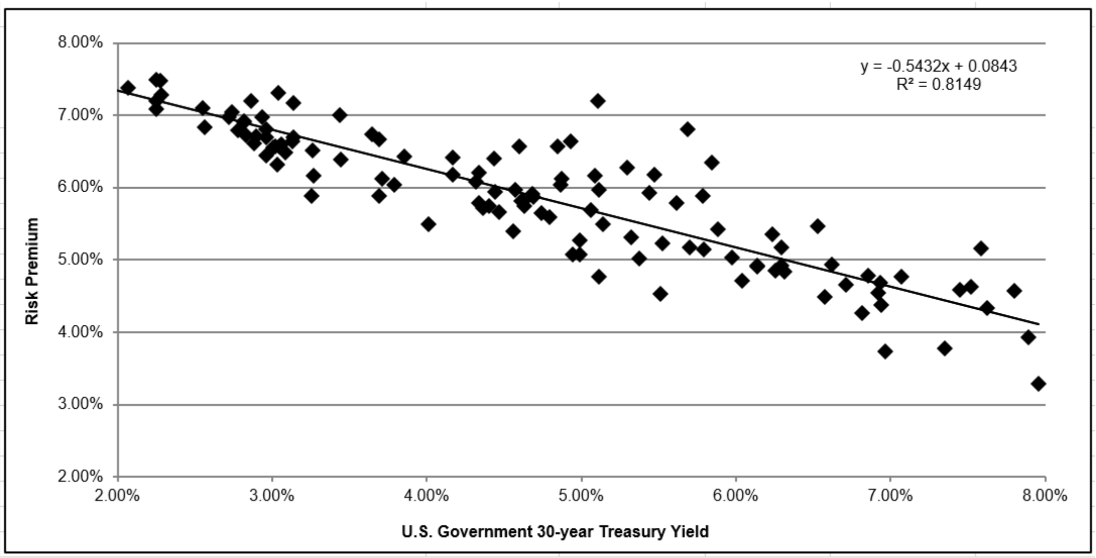


Figure **4**: Risk Premium Results - U.S. Electric[594]



At the oral hearing, Mr. Coyne explained the significance of the high correlation between ERP and bond yields as shown by the high R2 values of 0.86 and 0.82 for gas and electric utilities respectively:[595]

> So what this is trying to get at is how did utility commissions interpret everything that they looked at in these 1500 some odd cases and make a decision regarding allowed return in the investment environment they were in characterized by the bond yield in that period of time? And you can see the -- that's a very strong linear relationship as you can see the trendline.
>
> […] And I'm estimating that relationship because what I want to do is ask myself, given today's bond yields or projected bond yields, and everything we know about these 1500 decisions, what

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593 Exhibit B1-8-1, Appendix C, p. 65. Based on Mr. Coyne's Excel spreadsheet, Mr. Coyne seems to have averaged ROEs by quarter from Q1 1992 to Q4 2021 or Q42021. Thus, there are not 700 or 859 data points in Figure 1 or Figure 2, respectively.

594 Exhibit B1-8-1, Appendix C, p. 65.

595 Transcript Volume 4, p. 654, Lines 18–26 to p. 655, Lines 1–16.

would a regulator say about the allowed return, with no other information available to them but just based on bond yields. And it says that […] you can explain 86 or 82 percent of those decision just based by on knowing that bond yield in that period of time. It's a pretty strong association.

5.4.2 What is the Appropriate Bond Yield to Use?

Having estimated the parameters *a* and *b* in Equation (7) from historical data, the second step is to apply the regression's results (*a* and *b*) to long-term bond yields (Y) to estimate the ERP in Table 31 from Equation (7). To do so, Mr. Coyne uses both the current (30-day average) and forecast bond yields of the 30-year Treasury Yield. For the forecast bond yields, Mr. Coyne uses a near-term and a five-year forecast (see Table 31). In Mr. Coyne's view, the five-year forecast is the most applicable because investors are expecting increases in government bond yields and investors typically have a multi-year view of their required returns on equity.[596] For instance, the ERP of 6.32 percent for the US gas proxy group in the 4th column is estimated as follows:

U.S. Gas: $ERP = 0.0851 - 0.5775 \times Y$

$$ERP = 0.0851 - 0.5775 \times Y$$
$$ERP = 0.0851 - 0.5775 \times 0.038$$

$$ERP = 0.0632\ or\ 6.32\%$$

Then, the resulting ROE is computed using Equation (6):

$$ROE = ERP + Y$$
$$ROE = 6.32\% + 3.80\% = 10.12\%$$

Table 31: Risk Premium Results for FEI and FBC – October 2022[597]

	U.S. Gas Proxy Group			**U.S. Electric Proxy Group**		
	30-Day average yield on 30-year treasury bond	Q2 2023-Q2 2024 forecast for yield on 30-year treasury bond	**2024-2028 forecast for yield on 30-year treasury bond**	30-Day average yield on 30-year treasury bond	Q2 2023-Q2 2024 forecast for yield on 30-year treasury bond	**2024-2028 forecast for yield on 30-year treasury bond**
Yield	3.92%	4.00%	**3.80%**	3.92%	4.00%	**3.80%**
ERP	6.25%	6.20%	**6.32%**	6.30%	6.26%	**6.36%**
Resulting ROE[598]	10.17%	10.20%	**10.12%**	10.22%	10.26%	**10.16%**

5.4.3 Overall Risk Premium Model Results

While the Risk Premium Model is simple and easily replicable, Dr. Lesser points to a commonly cited weakness of the model: circularity, due to its reliance on prior regulatory decisions. He also highlights other potential flaws in

[596] Exhibit B1-8-1, Appendix C, pp. 65–67.

[597] Exhibit B1-50, Scenario A.2, Gas and Electric Excel spreadsheets, Tab "JMC-FEI 7 Risk Premium".

[598] Exhibit B1-50, p. 6: per Footnotes 3 and 4, the risk premium results do not include 50 bps for flotation costs and financial flexibility.

its implementation. For instance, the regression specification (with only one explanatory variable) assumes that no other factors can influence investors' expected return requirements (e.g. business risk, financial risk, capital structure, degree of regulated versus unregulated activities). So, unless this is true, the model specification suffers from "omitted variable bias" and the slope coefficient "*b*" is likely to be biased. Additionally, Dr. Lesser states that this approach fails to consider differences in risk associated with those previously established allowed returns, such that it will not capture the fundamental relationship between risk and return. Thus, the resulting ERP value may not reflect a risk-comparable ROE and thus may not meet the Fair Return Standard. Another problem is to select a historical period where the relationship between the ERP and bond yields is constant and representative of current capital market conditions.[599]

In summary, Dr. Lesser cautions regulators when using a regression model to calculate the relationship between historical ERPs and bond yields, as they must evaluate the model itself, the time period selected, and the validity of the implicit assumptions that the estimated relationship will be valid on a going-forward basis. In Dr. Lesser's view, simple linear models relating ERPs to bond yields are fraught with empirical estimation issues that can lead to biased parameter values.[600] Additionally, Dr Lesser states that models that use historical allowed returns to estimate ERP values suffer from unavoidable circularity.[601] Dr. Lesser also states that, based on his experience over the last 20 years, he does not recommend use of the Risk Premium methodology.[602]

In response to these critiques, Mr. Coyne remarks that, after hearing these and other arguments in the context of setting ROEs for electric transmission companies, FERC ultimately concluded:[603]

> The Risk Premium model has a strong theoretical basis. We continue to find that the defects of the Risk Premium model do not outweigh the benefits of model diversity and reduced volatility resulting from the averaging of more models. […] While the Commission in Opinion No. 569 noted its concerns with the Risk Premium model as proposed by the Briefing Order, the Commission found in Opinion No. 569-A that these concerns are mitigated by modifications that the Commission made to the Risk Premium model as well as the fact that the Commission will average the results of the Risk Premium with the DCF and CAPM. We reaffirm this finding here.

Mr. Coyne states that he agrees with FERC that the benefits of the Risk Premium Model outweigh its weaknesses and the model provides a stabilizing influence when averaged with the CAPM and DCF model, which can be especially attractive in the presence of volatile market and economic conditions.[604] At the oral hearing, Mr. Coyne explained that he likes to use multiple models, including the risk premium, as "they give you a little bit more resilience from the pure market-based models, the DCF and the CAPM, that tend to get whip-sawed by [fluid and dynamic market] circumstances". [605]

This stabilizing influence and resilience can be seen in the table below, which presents Mr. Coyne's ROEs from the Risk Premium Model at different points in time throughout the proceeding. Those results reflect Mr. Coyne's

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599 Exhibit A-3, pp. 65–66.
600 Exhibit A-3, p. 67.
601 Exhibit A2-3, p. 67.
602 Exhibit A2-8, Dr. Lesser Response to FortisBC IR 17.1.
603 Exhibit B1-8-1, Appendix C, p. 63.
604 Ibid.
605 Transcript Volume 3, p. 171, Lines 16–26 to p. 172, Lines 1–9.

preferred approach of using the five-year forecast bond yield as the basis to compute the ROE. For clarity, these results do not include an adder for financial flexibility and flotation costs.

Table 32: Mr. Coyne's Risk Premium Model's ROE Results[606]

	Canadian Regulated Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
December 2021[607]	n.a.	9.97%	9.97%	10.01%	10.01%
September 2022[608]	n.a.	10.12%	10.12%	10.17%	10.17%
October 2022[609]	n.a.	10.12%	10.12%	10.16%	10.16%

FortisBC submits that the Risk Premium Model produces results that are supportive of Mr. Coyne's recommendations and merits the BCUC's consideration due to its theoretical validity and stability. FortisBC states that Dr. Lesser accurately characterizes the Risk Premium Model as "in effect, a simpler version of the CAPM", simpler because it focuses on bond yields as one driver of the cost of capital. While the Risk Premium Model is simpler, FortisBC notes that FERC recognizes its theoretical validity and value, as it has adopted the Risk Premium Model as one of its three methods (which it weights equally) for determining the cost of capital for regulated electric transmission companies.[610]

FortisBC notes that Mr. Coyne's Risk Premium Model involved examining the allowed ROEs from a large sample of US gas and electric distribution companies from 1992 to 2021 to determine the existence of a high correlation between allowed ROEs and government bond yields. Mr. Coyne then applies the regression results to current and forecast bond yields, with the latter resulting in a ROE of 10.12 percent and 10.16 percent for the US gas and electric proxy groups, respectively, based on October 2022 data. FortisBC notes that the results based on *current* bond yields (Dr. Lesser's preference) would be slightly higher because forecast government bond yields are lower than current government bond yields in October 2022.[611]

FortisBC concludes that the Risk Premium Model results are consistent with Mr. Coyne's recommended ROEs for FEI and FBC, both in terms of direction and magnitude. FortisBC stresses that these results are based on US utilities that have, on average, much thicker common equity ratios than FEI and FBC. Other things being equal, FortisBC submits that one would expect the ROE values to be higher when applied to a utility with thinner equity.[612]

[606] Information in the table is compiled from the referenced footnotes within the table.
[607] Exhibit B1-8-1, Appendix C, Figures 1, p. 4 and Figure 2, p. 5.
[608] Exhibit B1-8-1-2, Figure 1, p. 2 and Figure 3, p. 3.
[609] Exhibit B1-50, Figures 3 and 4, p. 6.
[610] FortisBC Final Argument, p. 138.
[611] Ibid., pp. 138–139.
[612] Ibid., p. 139.

Positions of Parties

The CEC

The CEC notes that the Risk Premium Model is simpler to understand and its use as a check for reasonableness of results is appropriate.[613]

RCIA

RCIA is the only intervener that made detailed final submissions in relation to the Risk Premium Model. In RCIA's view, this model is simple and provides accurate and reliable estimations of ROE, as well as an intuitive framework to understand other FortisBC ROEs and how the selection of assumptions impact ROE estimates.[614] RCIA submits that, even though Mr. Coyne's ROE recommendations are only based on the CAPM and Multi-Stage DCF and that Mr. Coyne's Risk Premium Model is not directly applicable to Canadian utilities, important insights can be gained from the Risk Premium Model, namely that:

1) Approved ROEs can be modelled using a simple regression analysis, using the bond yield as the independent variable; and
2) A statistically significant multi-year linear relationship exists between interest rates (bond yields) and risk premiums derived from US utilities' approved ROEs.[615]

RCIA notes that, while the model shows an inverse correlation between bond yields and risk premiums, as bond yields rise, the risk premium decreases, but by less than the nominal value of the bond yield increase. As shown in the regression results of Figure 3 and Figure 4, when bond yields increase by 100 bps, the risk premium decreases by 58.32 bps and 55.08 bps for US gas and electric utilities, respectively.[616] Thus, as shown in Table 31 above, RCIA notes that higher interest rate assumptions result in higher ROEs. RCIA submits that, in Table 31, "the interest rates were boosted by the forecast to be 0.65% and 1.53% higher, resulting in 0.27% and 0.64% higher ROE for U.S. Gas estimate and 0.29% and 0.69% higher ROE for U.S. Electric estimate."[617]

In RCIA's view, the problem with inclusion of forecast data is that the implied results are only appropriate if the actual data (i.e. bond yield) equal the forecast. RCIA notes that the inclusion of forecast values is also a point of disagreement between Mr. Coyne and Dr. Lesser, the latter of whom states that actual market prices inherently reflect expectations while forecasts are unreliable. RCIA is also concerned with using the average of multiple years and time periods to generate the (forecast) bond yield assumption. In RCIA's view, this approach introduces randomness and error akin to Dr. Lesser's dartboard analogy ("If markets are not efficient, then no methodology is accurate. You might as well throw darts at a dartboard.")[618]

RCIA submits that Mr. Coyne applies judgement to bolster the results derived from the modelling to benefit his client. In RCIA's submission, the recommended ROE is higher than would be the case had actual bond yields

[613] The CEC Final Argument, p. 40.
[614] RCIA Final Argument, p. 4.
[615] RCIA Final Argument, pp. 5–6.
[616] Ibid., p. 6.
[617] Ibid., p. 8.
[618] Ibid., p. 9.

(which is the basis of the construction of the regression analysis) been used. The result is a bias that produces a higher than required result. At a minimum, RCIA submits that to be considered, the Risk Premium Model should be based on non-biased assumptions and results.[619]

FortisBC Reply Argument

FortisBC remarks that RCIA favours using the Risk Premium Model as a primary model and characterizes it as "simple and provid[ing] accurate and reliable estimations of ROE". FortisBC has two points in response to RCIA's submissions:[620]

1) RCIA's proposed ROEs are far below what the Risk Premium Model suggests; and
2) The Risk Premium Model output reinforces the CAPM and Multi-Stage DCF results.

On the first point, FortisBC states that it is impossible to reconcile RCIA's endorsement of the Risk Premium Model with the ROE values that RCIA is advocating. RCIA's proposed ROE values of between 8.0 percent and 8.75 percent are far below the Risk Premium Model output based on October 2022 *forecast* bond yields (10.12 percent and 10.16 percent for US gas and electric proxy groups, respectively) and *actual* bond yields (10.17 percent and 10.22 percent for US gas and electric proxy groups, respectively[621]). The results based on actual bond yields (RCIA's preference) are higher in October 2022 because forecast government bond yields were lower than actual government bond yields. FortisBC reiterates that the October 2022 outputs are relatively constant with Mr. Coyne's recommended ROEs for FEI and FBC, both in terms of direction and magnitude.[622]

On the second point, FortisBC notes that RCIA argues that the Risk Premium Model reveals a potential weakness in Mr. Coyne's other models. Specifically, RCIA observes that the Risk Premium Model suggests that the ROE should increase as interest rates increase, and notes that Mr. Coyne's CAPM and DCF results have decreased slightly in September 2022 relative to December 2021 despite increasing interest rates.[623] FortisBC agrees and emphasizes that Mr. Coyne explains the transitory nature of the September 2022 results and that the October 2022 results have increased markedly and shift back to approximate those from December 2021. FortisBC submits that "RCIA's notion that the transitory results in September 2022 calls the model itself into question is predicated on the fallacy that all models should produce the same results at all times".[624] The reason why Mr. Coyne and Dr. Lesser both favour the use of multiple models is because the models have their own strengths and weaknesses and respond differently in different conditions. Mr. Coyne considers various models to check the reasonableness of his model and any model may, at specific times and due to events such as market disruptions, result in estimates that would require adjustments or judgement. FortisBC notes that Dr. Lesser's practice is no different.[625]

619 RCIA Final Argument, p. 10.
620 FortisBC Reply Argument, pp. 73–74.
621 Exhibit B1-50, Scenario A.2, Gas and Electric Excel spreadsheets, Tab "JMC-FEI 7 Risk Premium".
622 FortisBC Reply Argument, p. 73.
623 Ibid.
624 Ibid., p. 74.
625 Ibid., pp. 73–74.

Panel Determination

The Panel considers that using multiple models recognizes that each of the models has its own strengths and weaknesses and responds differently in different conditions. Relying on more models is especially important at times when the pure market-based models like the DCF and CAPM tend to get whipsawed by volatility in the market. As a case in point, the Risk Premium Model yields ROE results that remain within a very narrow range of about 15 bps throughout the proceeding, whereas up and down movements in the CAPM and multi-stage DCF models have been a lot more pronounced at times.

Therefore, the Panel finds that considerable weight should be given to the use of a Risk Premium Model for the purposes of determining the appropriate ROE for FEI and FBC given the volatility in the market and economic conditions. The specific weight to be accorded the Risk Premium Model in the respective ROEs will be discussed in Section 6.3 (Overall Capital Structure and ROE).

The strengths of the Risk Premium Model outweigh its shortcomings. The Panel finds that a strength of the Risk Premium Model is its theoretical validity and stability. We also find that this model is easy to understand. A weakness of the Risk Premium Model is the circularity of the model, due to its reliance on prior regulatory decisions. However, the Risk Premium Model is not the only model that can be prone to similar circularity risks. For instance, in the DCF model, prior regulatory decisions on the proxy companies' authorized ROEs are likely to influence the inputs to the model such as utility stock prices. Consequently, the Panel considers that circularity concerns alone do not justify eliminating reliance on the Risk Premium Model, or any particular model, for determining the appropriate ROE for FEI and FBC. Instead, it is a factor in the overall consideration of model results.

Mr. Coyne states that he agrees with FERC that the benefits of the Risk Premium Model outweigh its weaknesses and the Risk Premium Model provides a stabilizing influence when averaged with the CAPM and DCF model, which can be especially attractive in the presence of volatile market and economic conditions. Although FERC's determinations are not binding on the BCUC, the Panel notes that FERC has recognized the theoretical validity and value of the Risk Premium Model, as it has adopted that model along with the CAPM and DCF model, which it weights equally for determining the cost of capital for regulated electric transmission companies in the US.

Having determined to give weight to the Risk Premium Model, the Panel must now decide what is the appropriate bond yield to use, whether current or forecast. To be consistent with its previous determination on the risk-free rate used in the CAPM (see Section 5.2.1), the Panel will also rely on the forecast for the yield on 30-year treasury bond, specifically the results using the five-year forecast:

Table 33: Mr. Coyne's Risk Premium Results - October 2022[626]

	Canadian Utilities	U.S. Gas Utilities	North American Gas Utilities	U.S. Electric Utilities	North American Electric Utilities
October 2022[627]	n.a.	10.12%	10.12%	10.16%	10.16%

[626] Information in the table is compiled from the referenced footnotes within the table.

[627] Exhibit B1-50, Figures 3 and 4, p. 6

Mr. Coyne did not adjust the Risk Premium Model ROE results by adding 50 bps to account for flotation costs or financial flexibility. The Panel understands that the Risk Premium Model relies on past regulatory decisions on authorized ROE to calculate the risk premium such that the underlying data points used in the equation are already inclusive of any adder regulators would have deemed appropriate.

Since there are not enough Canadian ROE decisions, Mr. Coyne has performed the regression analysis on US data only, and therefore, the Risk Premium Model results are applicable to US utilities. In the revised North American proxy groups from which Enbridge Inc. and Canadian Utilities Limited are removed, a majority of the proxy companies are from the US. As a result, the Panel finds that the Risk Premium Model ROE results are applicable to the revised North American proxy groups. Therefore, the Panel will use a Risk Premium Model ROE of 10.12 percent for FEI and 10.16 percent for FBC as it weights the different ROE models.

6.0 OVERALL PANEL DETERMINATION ON CAPITAL STRUCTURE AND ROE

Section 4 previously discussed the evidence and interveners' respective submissions on credit ratings and business risks as they relate to capital structure. In Section 5, the Panel reviews the various financial models used to calculate the ROE. In Section 6.1 below, the Panel considers FortisBC's and the interveners' recommended ROE, based largely on the results of these financial models before any flotation costs and financial flexibility adder and other adjustments. Section 6.2 focuses on the topic of flotation costs and financial flexibility. Finally, Section 6.3 considers FortisBC, the two experts (Mr. Coyne and Dr. Lesser), and the interveners' recommended capital structure and overall ROE, inclusive of all adders and other adjustments. Parties presented a range of reasonable possibilities in both the deemed equity component and allowed ROE in Stage 1. In the overall determination section, we give appropriate weight that reflects our findings above and make final determinations on the deemed equity component and allowed ROE for FEI and FBC, respectively.

6.1 ROE Before Adders and Other Considerations

FortisBC submits that the evidence in this proceeding supports a finding that the required cost of equity for FEI and FBC is, respectively, 10.1 percent (on 45 percent common equity) and 10.0 percent (on 40 percent common equity).[628] These figures are based on the US proxy groups and December 2021 data and consist of a simple average of Mr. Coyne's CAPM and Multi-Stage DCF model results. They are also inclusive of a 50-bps adder for flotation costs and financial flexibility.[629] FortisBC states that these proposed ROEs are based on the recommendations of Mr. Coyne, who is the only expert in this proceeding who conducted a full cost of capital analysis.[630]

In its final argument, FortisBC notes the experts' alignment on key aspects of the ROE analysis, including the use of multiple models, using Mr. Coyne's proxy groups with more reliance on North American proxy groups, and the reasonableness of relying primarily on the most recent October 2022 data.[631] FortisBC states that Mr. Coyne's model results based on October 2022 data align with current economic and market conditions[632] and

[628] FortisBC Final Argument, p. 121.
[629] Exhibit B1-8-1, Appendix C, Figure 1, p. 4, Figure 2, p. 5.
[630] FortisBC Final Argument, p. 121.
[631] Ibid., para. 244(b), p. 121.
[632] Ibid., para. 249, p. 124.

notes that there is a reasonable alignment between results based on the October 2022 data and the December 2021 data.[633]

BCOAPO points out that Mr. Coyne's original evidence, based on the December 2021 data, recommends ROEs for FEI and FBC of 10.1 percent and 10.0 percent, respectively but the updated information Mr. Coyne provided using October 2022 data results in ROEs of 9.5 percent and 9.63 percent for FEI and FBC, respectively[634]. Despite this, BCOAPO notes that FortisBC's position in its final argument remains the same as it was prior to the oral hearing. BCOAPO questions why FortisBC still pursues the higher ROEs in the face of more current data. BCOAPO submits that the evidence is clear that FortisBC's position is not based on the best evidence available and as such, FortisBC's applied-for ROE levels should not be approved.[635]

As this section focuses on the ROE before any adders for flotation costs, financial flexibility, or other considerations, subtracting 50 bps from the aforementioned FortisBC's requested ROEs yields ROEs of 9.51 percent for FEI and 9.50 percent for FBC, respectively.

Like FortisBC, the interveners have based their respective ROE recommendations on either a simple average of their CAPM and Multi-Stage DCF model ROEs (ICG, BCOAPO and the CEC) or on the CAPM ROE, only (RCIA), but have not incorporated the ROE derived from the Risk Premium Model into their ROE recommendations. Reflecting our cumulative determinations on the various inputs to the CAPM (such as a preference to use forecast bond yields to estimate the risk-free rate and a constant DCF model to estimate the forward-looking MRP, as well as giving equal weight to the historical and forward-looking MRP, and not including a Hamada adjustment or a size premium), we do not propose to further review the CAPM ROE recommendations made by ICG, BCOAPO and RCIA because they all favour different inputs into the CAPM. Similarly, our earlier acceptance of a 30-trading-day period to calculate utility stock prices and dividend yields in the Multi-Stage DCF model also means that we will not consider the Multi-Stage DCF ROE recommendations made by BCOAPO and the CEC that favour a 90-trading-day average. Consequently, we do not propose to review in detail the interveners' ROE recommendations before any flotation costs and financial flexibility adder and other adjustments.

6.2 Flotation Cost and Financial Flexibility

6.2.1 Flotation Cost

Flotation costs are associated with issuing new equity, which include legal fees, out-of-pocket expenditures for the preparation, filing, underwriting, and other costs associated with the issuance of common equity.[636] Both Mr. Coyne and Dr. Lesser note that regulators often include an allowance for flotation costs.[637] However, the experts have a difference in opinion on how flotation costs should be recovered and the size of the adjustment for flotation costs.

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633 FortisBC Final Argument, para. 295, p. 146.

634 These figures are based on 90-day average stock prices and interest rates.

635 BCOAPO Final Argument, p. 54.

636 Exhibit A2-3, p. 82, Exhibit B1-8-1, Appendix C, p. 69.

637 Ibid., Executive Summary, p. 2, Exhibit B1-8-1, Appendix C, p. 69.

Recovery Mechanism

Mr. Coyne submits that because the purpose of the allowed rate of return in a regulatory proceeding is to estimate the cost of capital the regulated company would incur to raise money in the "primary" markets, an estimate of the returns required by investors in the "secondary" markets must be adjusted for flotation costs in order to provide an estimate of the cost of capital that the regulated company requires.[638] Mr. Coyne explains that if FEI and FBC were standalone utilities and issued their own equities, the associated flotation costs could have been recovered in cost of service. In the absence of this possibility given the utilities are not publicly traded, the addition of flotation cost to the ROE is the only feasible approach.[639]

Furthermore, Mr. Coyne explains that flotation costs are part of the invested costs of the utility, which are reflected on the balance sheet under "paid in capital." They are not current expenses, and therefore, are not reflected on the income statement. Like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time, remain part of the cost structure and as such, should be recovered through ROE.[640] The effect of the ROE adder for flotation costs is to treat issuance costs as if they are a rate base item on which FEI and FBC earn a return that flows back to Fortis Inc. as compensation for incurring the costs.[641]

Mr. Coyne submits that flotation cost is compensated each and every year rather than only on the incremental amount of capital as a result of a change in capital structure. Mr. Coyne further explains that the equity is permanent capital, and flotation cost is a charge for having the equity infused into the company.[642] In other words, as Mr. Coyne notes, "unlike debt, equity has an indefinite life and does not mature. Therefore, costs associated with the equity issuance are recovered over the life of the equity."[643]

In contrast, Dr. Lesser states that he favours compensating utilities for the actual flotation costs incurred, and states it may be more reasonable to include actual flotation costs (or an estimate of those costs) as an expense to be recovered in the regulated utility's cost of service.[644] In particular, if the utility is not traded publicly, but is a subsidiary of a publicly traded parent, and the parent company issues new equity to finance investment by the utility subsidiary, then the most equitable way to compensate the utility is by allowing it to recover all of the known and measurable costs of the stock issuance, rather than through an arbitrary increase in allowed ROE that is unlikely to reflect those actual issuance costs.[645] Dr. Lesser elaborates that an adjustment for flotation costs to allowed ROE will compensate the utility based on its rate base, not on the actual flotation costs incurred, and that an arbitrary percentage is likely to overcompensate the utility for flotation costs.[646] Hence, Dr. Lesser points out that "FERC does not grant a flotation cost adjustment to allowed ROE unless the firm under review can demonstrate it issued stock and incurred flotation costs."[647]

638 Exhibit B1-8-1, Appendix C, p. 69.
639 Exhibit B1-9, BCUC IR 43.4.
640 Exhibit B1-21, Part 2, p. 22.
641 Transcript Volume 3, p. 346.
642 Ibid., pp. 342–343.
643 Exhibit B1-13, RCIA IR1 31.3.
644 Exhibit A2-3, p. 85.
645 Exhibit A2-20, BCUC IR 6.3.
646 Exhibit A2-3, p. 85.
647 Ibid.

Size of an ROE adder for Flotation Cost

Regarding the appropriate size of flotation costs, Mr. Coyne makes adjustments to the DCF and CAPM results by 50 bps for flotation costs and financing flexibility.[648] However, while Mr. Coyne does not provide a breakdown of the 50-bps adjustment separating flotation costs from financing flexibility, Mr. Coyne notes that for an electric proxy group in the US, flotation costs are typically in the range of 10 to 15 bps and the remainder would be for financing flexibility (i.e. 35 to 40 bps).[649]

Dr. Lesser provides his view on issuance costs as a percentage of equity issued and notes that flotation costs typically have ranged between two percent and five percent of issuance costs[650] to which Mr. Coyne assesses, "doesn't sound unreasonable."[651] Using an assumed flotation cost equal to five percent of total issuance cost and Dr. Lesser's methodology to calculate flotation cost, Mr. Coyne converts Dr. Lesser's data into basis points of ROE, indicating that issuance costs of that magnitude represent approximately 21 to 25 bps of ROE for the gas proxy groups and 19 to 25 bps for the electric proxy groups.[652] Mr. Coyne notes that his estimate of 10 to 15 bps and Dr. Lesser's estimates of 25 bps are "within the range of what we would expect to see for issuance costs."[653]

Table 34: Flotation Cost Adder: Dr. Lesser's Methodology

Flotation Cost Adder: Dr. Lesser's Methodology (basis points)

Proxy Group	FEI	FBC
Canadian Regulated	25	25
US Gas	21	
North American Gas	24	
US Electric		19
North American Electric		20

6.2.2 Financial Flexibility

Financial flexibility refers to a margin, or cushion, for unanticipated capital market conditions,[654] or also as spare borrowing capacity[655] and ability to continue to raise equity in challenging capital market conditions.[656]
Dr. Lesser and Mr. Coyne disagree on inclusion of costs for financial flexibility to compensate for raising capital. Also, if financial flexibility is accounted for, there are varying opinions as to whether the financial flexibility adder should form part of the allowed ROE or deemed equity component of the capital structure.

Dr. Lesser

Dr. Lesser notes that in the academic literature, financial flexibility appears to be defined as having spare borrowing capacity and additional cash-on-hand, and thus, appears to be more related to the optimal capital

648 Exhibit B1-8-1, Appendix C, p. 72.
649 Exhibit B1-9, BCUC IR 43.2; 50-bps adjustment less flotation costs range of 10-15 bps equals to 35–40 bps for financial flexibility costs as the residual.
650 Exhibit A2-3, p. 82.
651 Transcript Volume 4, p. 624, ll. 5-17 and p. 625, ll. 6-23.
652 Exhibit B1-25, BCUC IR1 6.1.
653 Transcript Volume 3, p. 354.
654 Exhibit A2-20, BCUC IR 6.6; 2013 Decision, p. 79.
655 Exhibit A2-20, BCUC IR 6.6.
656 Exhibit B1-8-1, Appendix C, p. 69.

structure and less one of the allowed ROE.[657] Therefore, because financial flexibility is related to capital structure, it is Dr. Lesser's opinion that, if the BCUC wishes to increase the allowed returns earned by FEI and FBC to account for financial flexibility, such flexibility is best incorporated into the capital structure the BCUC sets for FEI and FBC by adjusting each utility's deemed equity ratios.[658] He does not consider an adder for financial flexibility to be just and reasonable.[659] Dr. Lesser also explains that given the efficiency of capital markets, it is unclear why a regulated utility requires an allowance above its allowed ROE as a financial cushion to enable it to raise funds "under a variety of economic and market conditions," nor whether this "variety" of conditions is limited solely to financial crises, which are themselves undefined.[660] He questions whether the benefits to ratepayers of this financial cushion exceed the costs.[661]

Mr. Coyne

Mr. Coyne submits that financial flexibility is necessary so that utilities such as FEI and FBC have the ability to raise capital under a variety of economic and market conditions, including periods such as the financial crisis of 2008/2009 and the COVID pandemic of 2020 to 2022.[662]

Additionally, Mr. Coyne submits that the optimal approach would be to establish financial parity with the US peer group, so that from an investor perspective, they are receiving equivalent returns and the utility would have comparable financial strength during all market conditions.[663] Mr. Coyne submits that if a Canadian regulator was looking to establish financial parity with US peers, then establishing comparable equity ratios (in the 50 percent to 52 percent range) and comparable allowed ROEs (9.5 percent to 10.0 percent range) would accomplish that objective,[664] and in doing so, would obviate the need for a "financial flexibility" adder to the ROE, as the Canadian utility would now have financial comparability to its US peers which do not have an equivalent adder.[665]

In response to undertakings to the oral hearing, Mr. Coyne performed a WACC analysis to calculate how the proposed 50-bps flotation cost and financial flexibility ROE adder can be reflected in the capital structure. Mr. Coyne determined that FEI's deemed equity ratio would need to increase by 2.0 percent to 2.3 percent for FEI and by 2.1 percent for FBC to account for recovery of flotation costs and financial flexibility through each utility's deemed capital structure. The results are summarized in the following table:

[657] Exhibit A2-20, BCUC IR 6.6.
[658] Ibid.
[659] Ibid.
[660] Ibid.
[661] Ibid.
[662] Exhibit B1-9, BCUC IR 43.1.
[663] Exhibit B1-51, BCUC IR 1.3.
[664] Ibid., BCUC IR 1.1.
[665] Ibid.

Table 35: Adjustment to Equity Ratio[666]

Adjustment to Equity Ratio for Flotation Costs and Financial Flexibility	Equity Ratio	Adjusted for Flotation and Financial Flexibility
FEI – current	38.5%	40.51%
FEI – proposed	45.0%	47.34%
FBC – current/proposed	40.0%	42.10%

As noted above, Mr. Coyne does not provide a breakdown of the 50-bps adjustment separating flotation costs from financing flexibility but Concentric explains that for an electric proxy group in the US, flotation costs are typically in the range of 10 to 15 bps and the remainder would be for financing flexibility (i.e. 35 to 40 bps).[667]

FortisBC

FortisBC submits that an adjustment for financial flexibility is required to compensate FortisBC for the additional margin of equity above approved equity ratio that it must maintain to remain compliant with the ring-fencing provision. FortisBC explains that ring-fencing occurs when a regulated public utility business financially separates itself from a parent company that engages in non-regulated business in order to mitigate possible risks arising from the financial status of the parent companies and non-regulated affiliates. A common concern cited in support of ring-fencing is the potential for a parent company to leverage the utility beyond the allowed equity thickness so as to earn an equity return on what is, in reality, debt financing.[668] Therefore, in order to consistently comply with this condition and to manage market volatilities, FortisBC explains that FEI maintains a cushion in its equity structure since its actual capital structure is not constant and will inevitably fluctuate depending on its financing needs.[669]

FortisBC argues that most Canadian regulators apply a premium to the approved ROE to account for the needed financial flexibility. In contrast, the majority of US regulators do not "deem" the equity thickness and rely upon the utility's actual stand-alone capital structure at the end of the test year.[670] FortisBC further states that the financial flexibility adder to the allowed ROE recognizes this fact and provides some compensation to the equity investor for the added layer of equity it provides above the regulated common equity ratio. In the absence of the financial flexibility adder, FEI would not be compensated for the additional margin of equity above approved equity ratio that it must maintain to remain compliant with this provision.[671]

In the oral hearing, FortisBC explained to the Panel that it tries to be in a position where it is "not slipping below the level of equity in the deemed [capital] structure."[672] FortisBC confirms its strategy to include financial flexibility in order to manage a capitalization that is "conservative and takes into account market disruptions so

[666] Exhibit B1-50, Undertaking No. 2, Attachment U.2.
[667] Exhibit B1-9, BCUC IR 43.2; 50-bps adjustment less flotation costs range of 10–15 bps equals to 35-40bps for financial flexibility costs as the residual.
[668] Exhibit B1-51, BCUC IR 2.1.1.
[669] Exhibit B1-51, BCUC IR 2.1.1.
[670] Exhibit B1-50, Undertaking #2, p. 1.
[671] Exhibit B1-51, BCUC IR 2.1.1.
[672] Transcript Volume 5B, p. 858.

that we [FortisBC] are never in a position where we're [FortisBC] over levered", regardless of whether it has an actual equity thickness of 38.5 percent or 45 percent or a different equity thickness.[673] An excerpt from the Transcript for the oral hearing is provided below:[674]

> COMMISSIONER LOSKI: I have a follow-up question, Mr. Lorimer. That strategy you just described, do you anticipate that would be the same if you have an equity thickness of 38 and a half percent or 45 percent or something else?
>
> MR. LORIMER: A: You know, to me it's a good strategy in either case. You know, I think that, you know, provides that level of comfort that we're not straying too far over and always on the proper side of the allowed return -- or the allowed equity fitness. I think to the extent you got, you know, less and less levered and you got a view from our rating agencies that they were comfortable, I guess, with the amount of leverage that we had. You know, there's probably more of an opportunity that more -- a bit less conservative on how that's done. But, you know, generally, like I'd like to be in a position where I can say that we're not slipping below the level of equity in the deemed structure. And especially for FEI, I guess, where the ring-fencing provisions are in and, you know, the requirements to keep at that level are a little bit more firm. You know, try to make sure that we're always cognizant of those provisions as well.

In addition, FortisBC submits that the existing 50-bps adder is helping to sustain FEI and FBC's existing credit ratings. The removal of the adder could be viewed as credit negative, particularly if the adjustment becomes "lost in broader business and financial risk considerations if evaluated with equity ratios."[675]

Positions of Parties

FortisBC submits that the BCUC should find that issuance costs[676] for FEI and FBC are reasonably estimated as being at least 25 bps.[677] With regards to financing flexibility, FortisBC submits that firstly, it compensates the utility for maintaining a buffer of equity above the deemed equity ratio, which is key to financial integrity. Second, from the perspective of comparable earnings and capital attraction, it addresses the lower overall returns in Canada relative to US companies with which Canadian utilities compete for capital.[678] In addition, FortisBC submits that the "existing 50 bps adder is helping to sustain FEI's and FBC's existing credit ratings."[679]

The CEC, ICG and BCOAPO support FEI's proposed adders for flotation costs and financial flexibility to varying degrees.

The CEC and ICG support a 50-bps adder for flotation costs and financial flexibility.[680]

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[673] Transcript Volume 5B, p. 857.
[674] Ibid., pp. 857– 859.
[675] Exhibit B1-51, BCUC Undertaking IR 1.3.
[676] The terms "floatation costs" and "issuance costs" are used interchangeably.
[677] FEI and FBC Final Argument, p. 184.
[678] Ibid.
[679] FortisBC Final Argument, pp. 191–192.
[680] The CEC Final Argument, p. 57, ICG Final Argument, p. 17. It is noted that the CEC and ICG have double-counted the 50-bps adder, as they both added 50 bps to ROE figures that were already inclusive of a 50-bps adder for flotation costs and financial flexibility.

The CEC submits that the continuation of a 50-bps adder for flotation costs and financial flexibility is warranted and reasonable.[681] In addition, the CEC submits that a company may raise more capital than explicitly needed and carry a buffer amount of equity above its deemed equity ratio thus supporting its financial flexibility and integrity which “also goes some distance to compensate for lower overall returns in Canada relative to US companies.”[682] The CEC submits that US utilities do not have an adder for flotation costs and financial flexibility, and that US utilities have in fact been provided considerable flexibility.[683] The CEC suggests that the BCUC may want to enable utilities in BC to have some of the flexibilities US utilities use to avoid the need for an explicit adder. Furthermore, the CEC recommends that in the processes triggered out of this proceeding, it would be useful to ask FEI, as the Benchmark Utility, to recommend to the BCUC flexible processes that US utilities have which could make the cost of capital processes simpler and operational without the need for adders.[684] BCOAPO does not disagree that issuance costs are valid but, in BCOAPO’s submission, there is not sufficient evidence on the record to establish any specific ROE adjustment. “At best, BCOAPO submits that it can confidently opine that it is likely no more than 25 basis points and could be materially less.”[685]

BCOAPO also argues that access to capital under reasonable terms and conditions is already one of the considerations involved in determining the appropriate capital structure for each of FEI and FBC. As a result, BCOAPO submits that the inclusion of any market accessibility considerations in the determination of the appropriate ROE and the equity ratio is unjustifiable, as it results in “double-counting” and skews the results higher.[686] BCOAPO acknowledges that, in its final argument, FortisBC adopts Mr. Coyne’s position that the flotation adjustment also serves to recognize that authorized equity ratios in Canada are less than those in the US.[687]

Overall, BCOAPO submits that the flotation cost adjustment of 50 bps is reasonable provided the BCUC recognizes that a portion of adjustment is to account for differences in the authorized equity ratios in Canada versus the US and this is recognized when setting the equity ratios for FEI and FBC.[688]

In its reply argument, FortisBC notes that interveners acknowledge that a fair return must account for flotation costs and financial flexibility.[689]

Panel Determination

Financial Flexibility

For the reasons set out below, the Panel finds that the appropriate way to account for required financial flexibility is to adjust the utility’s capital structure.

[681] The CEC Final Argument, p. 57.
[682] Ibid.
[683] Ibid., p. 58.
[684] Ibid.
[685] BCOAPO Final Argument, p. 56.
[686] Ibid., pp. 56–57.
[687] BCOAPO Final Argument, p. 57.
[688] Ibid.
[689] FortisBC Reply Argument, p. 75.

The Panel accepts Dr. Lesser's statement that financial flexibility appears to be defined as having spare borrowing capacity and additional cash-on-hand, and thus, appears to be more related to the optimal capital structure and less one of the allowed ROE.[690]

However, Dr. Lesser concludes from this position that flexibility is best incorporated into the capital structure the BCUC sets for FEI and FBC by adjusting each utility's deemed equity ratios. He therefore does not consider an adder for financial flexibility to be just and reasonable.

Mr. Coyne does not appear to disagree. He submits that "if a Canadian regulator was looking to establish financial parity with US peers, then establishing comparable equity ratios (in the 50 percent to 52 percent range) and comparable allowed ROEs (9.5 percent to -10.0 percent range) would accomplish that objective[691] – and in doing so, would obviate the need for a 'financial flexibility' adder to the ROE, as the Canadian utility would now have financial comparability to its U.S. peers which do not have an equivalent adder".
Having found Dr. Lesser's approach to dealing with financial flexibility to be reasonable, the Panel will consider the issue of financial flexibility when it determines the approved capital structure for the two FortisBC public utilities.

Flotation Costs

The Panel accepts that any reasonable and prudently incurred flotation costs incurred by a public utility are recoverable from ratepayers, over and above the approved costs of capital. However, there is no evidence before the Panel that FEI or FBC incurs any flotation costs and therefore there are no costs to recover. Instead, FEI and FBC argue that because their parent incurs flotation costs on their behalf, FEI and FBC should be entitled to a Flotation Cost "adder".

The Panel disagrees. Generally speaking, costs incurred by an unregulated parent are not recoverable from a regulated subsidiary, unless those costs are directly allocated and billed to the subsidiary for services legitimately performed by the parent. This can include approved allocations of costs forecast or incurred by the parent on behalf of its regulated subsidiaries. However, there is no direct link evident to the Panel between the proposed flotation cost adder and actual costs incurred or expected to be incurred by the parent. For example, the adder will be the same if there is an annual equity injection by the parent or if such equity injection only occurs every five years or never occurs.

The Panel finds that the proposed flotation cost adder is too vague to be a just and reasonable expense recoverable from ratepayers. It is a very rough estimate of the actual flotation costs of shares issued by the parent when it issues its own shares to obtain the funds used to purchase the shares of its subsidiaries. Therefore, we reject the proposal to use the flotation cost adder.

FEI and FBC can request recovery of actual costs incurred by the parent by providing applicable invoices or other supporting documentation from the parent when FEI and FBC issue additional equity. That supporting documentation should provide enough detail to enable the BCUC to review it to determine that is a just and reasonable expenditure. Those expenditures, if and as incurred, can be recovered from the ratepayers of FEI, or

[690] Exhibit A2-20, BCUC IR 6.6.
[691] Exhibit B1-51, BCUC IR 1.1.

FBC as the case may be, following review and approval as part of each utility's Revenue Requirement process in the normal course.

6.3 Overall Capital Structure and ROE

Since experts, and the interveners' respective submissions on capital structure, financial model ROE results, adders and other adjustments, have already been reviewed in previous sections, this section will narrowly focus on jointly presenting the interveners' recommended capital structure and overall ROE figures, inclusive of all adders for flotation costs, financial flexibility and other considerations.

FortisBC submits that the BCUC should approve, in accordance with the Fair Return Standard, FEI's proposed common equity ratio of 45 percent with an ROE of 10.1 percent, and FBC's proposed common equity ratio of 40 percent with an ROE of 10.0 percent.[692] These figures are based on the US proxy groups and December 2021 data and consist of a simple average of Mr. Coyne's CAPM and Multi-Stage DCF model results. They are also inclusive of a 50-bps adder for flotation costs and financial flexibility.[693]

Mr. Coyne's recommended increase of FEI's equity ratio from 38.5 percent to 45.0 percent is due primarily to higher business risks as compared to 2016, which include accounting for "elevated Energy Transition risk in BC".[694] Further, Mr. Coyne submits that his recommended 45.0 percent equity ratio for FEI is the "approximate midpoint between average deemed equity ratio for Canadian investor-owned gas distribution companies and the authorized equity ratio for U.S. gas distribution companies since January 2020."[695]

Mr. Coyne explains that capital structure and the cost of common equity are closely linked in determining the fair return for regulated utilities. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks in the form of financial leverage to which their shareholders are exposed. Accordingly, regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.[696]

In its 2013 Decision, the BCUC stated:

> The Commission Panel confirms that the approval of rates to meet the FRS [Fair Return Standard] is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel examines the overall return, i.e., the ROE and the common equity component, allowed to the utility.[697]

Because capital structure and ROE are inextricably linked, Mr. Coyne compares the weighted ROEs (authorized equity return multiplied by deemed equity ratio) for FEI and other large Canadian investor-owned gas distribution companies in Table 36.

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[692] FortisBC Final Argument, p. 3.
[693] Exhibit B1-8-1, Figure 1 and Footnote 1, p. 4, Figure 2 and Footnote 2, p. 5.
[694] Exhibit B1-20, BCUC IR 76.1.1.1.
[695] Ibid., BCUC IR 71.8.
[696] Exhibit B1-8-1, Appendix C, p. 147.
[697] 2013 Decision, p. 12.

Table 36: Comparison of Authorized Equity Returns for FEI[698]

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Energy Inc. (existing)	8.75%	38.50%	3.37%
FortisBC Energy Inc. (proposed)	10.1%	45.00%	4.55%
ATCO Gas	8.50%	37.00%	3.15%
Enbridge Gas[224]	8.66%	36.00%	3.12%
Energir[225]	8.90%	38.50%	3.43%
Canadian Gas Average	8.69%	37.17%	3.23%
Canadian Gas Median	8.66%	37.00%	3.15%
U.S Gas LDC Average	9.48%	52.0%	4.93%
U.S. Gas Proxy Group Average	9.45%	53.4%	5.05%

As shown in the above table, FEI's current weighted equity return of 3.37 percent is within the range of other large gas distributors in Canada, with Energir having the highest weighed ROE. Mr. Coyne states that the proposed weighted ROE for FEI, at 4.55 percent, while higher than its Canadian peers, is justified by both the shift in overall industry risk due to the Energy Transition and updated market return data, as well as by averages for the US gas proxy group.[699]

Table 37 presents a comparison of authorized ROE, deemed equity ratios, and weighted ROEs for other Canadian investor-owned electric distribution companies. As shown in that table, FBC's weighted equity return, at 3.66 percent, is within the range of weighted equity returns in Canada, with Newfoundland Power at 3.83 percent having the highest weighted ROE. Mr. Coyne states that the proposed weighted ROE for FBC, at 4.00 percent, is more in line with FBC's current risk profile and current market data and moves the company closer to, but not within the range of, its US peers.[700]

Table 37: Comparison of Authorized Equity Returns for FBC[701]

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Inc. (existing)	9.15%	40.00%	3.66%
FortisBC Inc. (proposed)	10.0%	40.00%	4.00%
ATCO Electric	8.50%	37.00%	3.15%
Nova Scotia Power	9.00%	37.50%	3.38%
Hydro One Ltd.	8.66%	40.00%	3.34%
Newfoundland Power	8.50%	45.00%	3.83%
FortisAlberta	8.50%	37.00%	3.15%
Maritime Electric	9.35%	40.00%	3.74%
Canadian Electric Average	8.75%	39.42%	3.45%
Canadian Electric Median	8.50%	38.75%	3.36%
U.S. Electric Average	9.50%	49.64%	4.72%
U.S. Electric Proxy Group Average	9.59%	49.76%	4.77%

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698 Exhibit B1-8-1, Appendix C, Figure 64, p. 149.

699 Ibid., Appendix C, pp. 149–150.

700 Exhibit B1-8-1, Appendix C, p. 151.

701 Ibid., Figure 65, p. 151.

Mr. Coyne differentiates business and financial risk in the following manner: business risk is inherent in a company's operations whereas financial risk relates to fixed obligations, but both are taken together to establish return requirements. Mr. Coyne states, "[b]usiness risk is the risk inherent in the company's operations, irrespective of how the company is financed. Business risk for a regulated utility results from variability in cash flows and earnings that impact the ability of the utility to recover its costs including the fair return on, and of, its capital in a timely manner." [702] Mr. Coyne notes that the BCUC has typically found the level of business risk to be an important factor in determining the allowed capital structure, and bases his capital structure recommendations on this risk analysis. For financial risk, Mr. Coyne explains financial risk exists to the extent a company incurs fixed obligations in financing its operations as evidenced by the relative percentages of debt and equity in the capital structure.[703]

In comparison, Dr. Lesser describes business risks as generally reflected in the determination of the allowed ROE whereas financial risks are most directly related to a firm's capital structure, credit rating, and cost of debt.[704] Dr. Lesser notes that business risk can encompass multiple dimensions and regulators would likely have to make subjective determinations of these differences, their significance, and appropriate ways to compensate for the differences. That might entail adjustments to allowed ROE or it might entail other mechanisms, such as creating or modifying balance account mechanisms.[705] Dr. Lesser states, one may have to adjust the equity return to account for certain business risks and adjust the capital structure to account for financial risk.[706] In contrast, Mr. Coyne describes the return to the equity investor as a function of both the equity ratio and the authorized ROE.[707]

Positions of Parties

The views of the Interveners on the appropriate capital structure for FEI and FBC are summarized in Table 38 and Table 39 below. For each of BCOAPO, the CEC and ICG, their recommended overall ROE figures in those two tables are inclusive of a 50-bps adder for financial flexibility and flotation cost. The BCUC calculates the interveners' resulting recommended weighted ROEs to facilitate the comparison with FortisBC's requests on capital structure and ROE.

Table 38: Capital Structure and ROE for FEI[708]

	Recommended Equity Component	Recommended Overall ROE	Recommended Weighted ROE
BCOAPO	40.00-42.00%	9.50%	3.80-3.99%
The CEC	40.00%	9.62%	3.85%
RCIA	40.00%	8.00-8.75%	3.20-3.50%

[702] Exhibit B1-8-1, Appendix C, p. 73.
[703] Ibid.
[704] Exhibit A2-24, BCOAPO IR 14.1.
[705] Exhibit A2-5, BCOAPO IR 10.
[706] Oral Hearing Transcript, Volume 4, p. 631.
[707] Exhibit B1-9, BCUC IR 60.2.
[708] BCOAPO Final Argument, pp. 65, 58, The CEC Final Argument, pp. 47, 43, RCIA Final Argument, pp. 31, 35, Recommended weighted ROE calculated by the BCUC.

Table 39: Capital Structure and ROE for FBC[709]

	Recommended Equity Component	Recommended ROE	Recommended Weighted ROE
ICG	38.50%	8.80%	3.39%
BCOAPO	40.00%	9.50%	3.80%
The CEC	40.00%	9.56%	3.82%
RCIA	40.00%	8.00-8.75%	3.20-3.50%

The following summarizes FortisBC's reply as it relates to interveners' submissions on the utilities' recommended capital structure, overall ROEs and/or the interplay between those two concepts.

ICG

With respect to ICG's submission, FortisBC highlights ICG's internal inconsistent reasoning to reach its low result:

i) On the one hand, ICG agrees that the BCUC should give the greatest weight to the North American proxy group when determining the ROE, which is, "no doubt, influenced by the fact that this tends to reduce FBC's ROE significantly relative to using the Canadian proxy group"; and

ii) On the other hand, ICG does the opposite to determine the common equity ratio as it advocates using the simple Canadian utilities median of 38.75 percent equity, rounded down without explanation to 38.5 percent, and giving "no weight" to the same U.S. proxy group companies that ICG advocates using for the ROE calculation. As the North American electric proxy group has an average equity ratio well above FBC's proposed equity ratio, ICG's approach tends to suppress the common equity ratio as well. FortisBC stresses that ICG's differing approaches are internally inconsistent because the common equity ratio and ROE and intertwined; ROE determinations are affected by the common equity ratio, and *vice versa*. FortisBC remarks that all the October 2022 ROE calculations based on the North American proxy group, which ICG wants to use, assume that the BCUC has accepted FBC's proposed common equity ratio of 40 percent. Even then, the U.S. electric proxy companies still have about 10 percent thicker equity on average (49.7 percent), such that the differential with the North American electric proxy group is substantial. FortisBC submits that FBC's ROE would be even more understated if the BCUC were to accept ICG's position of 38.5 percent equity. Applying a Hamada adjustment to the Lesser CAPM Results (30-day average stock prices and interest rates) for the North American proxy group at 38.5 percent equity increases the estimated ROE by 35 bps to 7.95 percent.[710]

Finally, FortisBC points out that ICG has not accounted for any size premium for FBC and offers no explanation for it. FortisBC stresses that both experts agree that the CAPM will understate ROE results for companies like FBC that are smaller than the proxy companies and reiterates that the size premium calculated by Mr. Coyne based on the Duff & Phelps approach is 105 bps.[711]

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[709] ICG Final Argument, pp. 16,15, BCOAPO Final Argument, pp. 70, 58, The CEC Final Argument, pp. 51, 43, RCIA Final Argument, pp. 31, 35. Recommended weighted ROE calculated by the BCUC.

[710] FortisBC Reply Argument, pp. 55–56.

[711] Ibid., p. 55.

BCOAPO

With respect to BCOAPO's submission, FortisBC notes that BCOAPO endorses an ROE of 9.5 percent for both FEI and FBC, on 40 to 42 percent and 40 percent equity, respectively, inclusive of a 50-bps adjustment for flotation and financial flexibility, an adjustment for FEI and FBC's lower equity thickness, and a size premium for FBC. FortisBC states that BCOAPO's recommendations acknowledge that the cost of capital has increased since the BCUC last set FEI and FBC's respective ROEs but that BCOAPO's calculations still understate the required ROE due to its reliance on an implausibly low Lesser CAPM result and mathematical errors.[712] FortisBC states that the latter error skews BCOAPO's results downward significantly.[713]

Based on BCOAPO's methodology, FortisBC demonstrates how BCOAPO's recommended CAPM ROE should have been calculated as 9.51 percent instead of 9.01 percent, an error which carries forward when BCOAPO averages the CAPM and Multi-Stage DCF model results. The correction of BCOAPO's mathematical error in the overall average of BCOAPO's proposed CAPM and multi-stage DCF model for the BCOAPO-revised North American electric proxy group increases BCOAPO's ROE result from 9.04 percent to 9.29 percent.[714]

Furthermore, as noted in Section 5.2.2, FortisBC submits that the 12-bps upward adjustment for FEI that BCOAPO adds to account for its thinner proposed equity than the 45 percent basis for all the ROE model calculations is clearly insufficient. Applying a Hamada adjustment to Mr. Coyne's CAPM results for the BCOAPO-revised North American proxy group at 42 percent equity increases BCOAPO's estimated ROE by 45 bps. FortisBC submits that the ROE increase would be even larger at 40 percent (i.e. the lower end of the BCOAPO's recommended range for FEI's equity thickness).[715] Finally, FortisBC submits that BCOAPO miscalculates FBC's size premium and correcting that error alone yields an ROE of more than 10 percent. Indeed, FortisBC submits that the proper 105-bps size adjustment alone would increase BCOAPO's calculated ROE for FBC to approximately 10.09 percent, assuming 40 percent equity.[716]

The CEC

With respect to the CEC's submission, FortisBC stresses that the CEC's significant concessions, in terms of increased equity thickness and ROE for FEI and increased ROE for FBC, are indicative of the overwhelming body of evidence demonstrating that the cost of equity has increased since the BCUC last considered FEI and FBC's respective ROEs. However, FortisBC views the CEC's recommended ROEs as being understated in two respects.

The first relates to the 80-bps deduction which accounts for most of the difference between the CEC's and Mr. Coyne's respective recommendations. The second relates to the interplay between equity thickness and ROE. FortisBC points out that the modelling underlying the CEC's recommendations for FEI is premised on a 45 percent common equity ratio, but the CEC is recommending a 40 percent ratio. FortisBC states that both experts confirm that increasing the disparity between FEI's equity ratio and that of the proxy group will increase the required ROE. FortisBC points out that Mr. Coyne chooses not to include a Hamada adjustment to his CAPM results only because he also recommends to increase FEI's equity ratio to 45 percent, thus significantly

[712] FortisBC Reply Argument, p. 44.
[713] Ibid., p. 45.
[714] Ibid., p. 46.
[715] FortisBC Reply Argument, p. 46.
[716] Ibid., p. 47.

narrowing the equity disparity with the gas proxy groups. But FortisBC states that this logic will no longer hold at the CEC's recommended 40 percent equity for FEI and applying a Hamada adjustment to Mr. Coyne's CAPM results for the North American gas proxy group at 40 percent equity would increase the estimated ROE for FEI by 48 bps to 10.78 percent.[717]

RCIA

With respect to RCIA's submission, FortisBC points out that RCIA arrives at its proposed ROEs of 8.00 percent to 8.75 percent for both FEI and FBC by ignoring the Multi-Stage DCF model (and the higher results[718]) altogether, by applying unsupported downward adjustments to Mr. Coyne's CAPM results, by ignoring the most current data, and by failing to account for differentials in financial risk and size premium. FortisBC submits that updating RCIA's own calculations to reflect October 2022 data alone significantly closes the gap with Mr. Coyne's recommendations, and rectifying other shortcomings brings them further into alignment.[719]

As explained in Section 5.2.5, with the first adjustment, RCIA's CAPM-based ROE would increase to 9.43 percent, which is significantly higher than its proposed 8.00 percent to 8.75 percent. Averaging this 9.43 percent with the Multi-Stage DCF model results for the Canadian proxy group of 10.46 percent based on October 2022 data would result in an ROE of 9.94 percent for both FEI and FBC. FortisBC submits that these values support Mr. Coyne's recommendations of 10.1 percent on 45 percent common equity for FEI and 10.0 percent on 40 percent common equity for FBC.[720] Then, applying a Hamada adjustment to RCIA's own CAPM calculations, updated to October 2022 data for the Canadian proxy group at 40 percent equity, would increase the estimated ROE for FEI and FBC by 47 bps to 9.90 percent.[721] And adding a size premium for FBC, which Mr. Coyne calculates at 105 bps based on Duff & Phelps data, would further increase the CAPM ROE for FBC.[722]

Overall Panel Determination on Capital Structure and ROE

Deemed Equity Component

FortisBC proposes an equity thickness of 45.0 percent for FEI and 40.0 percent for FBC, while interveners recommend 40.0 percent to 42.0 percent for FEI and 38.5 percent to 40.0 percent for FBC. Mr. Coyne observes that his recommended 45.0 percent equity ratio for FEI is the approximate midpoint between the average equity ratio of Canadian investor-owned gas distribution companies and US gas distribution companies.

While the Panel views the 37.0 percent to 53.4 percent equity thickness of comparable Canadian and US gas utilities (see Table 36 above) as a possible range of equity thickness for FEI, this does not imply that any point within the range will meet the Fair Return Standard. The Panel is not convinced that determining a deemed equity component can be done in a precise manner such as taking an average between certain numbers. A capital structure that is optimal for FEI or FBC may not be optimal for other utilities. The Panel must assess the business risk, financial risk, and other items such as accounting for differences in leverage in the proxy group

[717] FortisBC Reply Argument, pp. 43–44.
[718] The Multi-Stage DCF model results are higher than the CAPM results based on October 2022 data, not December 2021 data.
[719] FortisBC Reply Argument, p. 47.
[720] FortisBC Reply Argument, pp. 50–51.
[721] 9.43% + 0.47% = 9.90%.
[722] FortisBC Reply Argument, p. 51.

companies used in the modelling (e.g. a Hamada adjustment in the CAPM results) and allowing for financial flexibility, all of which may be difficult to quantify when estimating the required equity component.

Further, Mr. Coyne's "midpoint" observation does not align with his recommendation for FBC's deemed equity ratio of 40.0 percent, where the Canadian electric average is 39.42 percent and the US electric proxy group average is 49.76 percent as shown in Table 37 above.

Throughout this decision, the Panel notes that certain factors should be considered as part of the capital structure determination, namely:

- Compensation to the shareholder for the business and financial risks of FEI and FBC (Sections 4.2 and 4.3).
- The approach to addressing the discrepancy in financial risk through an adjustment to the capital structure (Section 5.2.2).
- Consideration of financial flexibility to the extent that it is required for FEI and FBC to have spare borrowing capacity. However, Mr. Coyne submits that financial flexibility is not necessary if the regulator establishes comparable equity ratios in the 50 percent to 52 percent range and comparable ROEs in the 9.5 percent to 10.0 percent range (Section 6.2.2).
- Benefits of maintaining the current credit ratings of FEI and FBC (Section 4.1).

In Section 4 of this decision, we assess how business risk has changed since 2016 for FEI and 2013 for FBC from the perspective of their shareholder and investors. We discuss that Energy Transition risk for FEI is a real shareholder risk in Section 4.2, while other increased risk categories are largely borne by ratepayers. Overall, an increase in FEI's equity component is warranted to compensate for the increased risks faced by FEI's shareholder and investors.

The Panel recognizes that Dr. Lesser describes business risks to be generally reflected in the determination of the allowed ROE because financial risks are most directly related to a firm's capital structure, credit rating, and cost of debt. However, there is no supporting evidence for his view. In contrast, Mr. Coyne's view is that there is a need to adjust either the capital structure or the ROE. Therefore, it follows that regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met.

For practical reasons, given the inter-relationship of all these factors, the Panel will continue the approach of reflecting changes in business risks as adjustments to the capital structure, recognizing that it will also impact the ROE. This approach is consistent with past BCUC decisions and provides room for the exercise of informed judgment.

In determining the optimal capital structure for FEI, the only expert evidence is Mr. Coyne's recommendation of 45.0 percent and his cost of capital analysis is largely built around this 45.0 percent equity thickness. Further, Mr. Coyne chooses not to make Hamada adjustments to his own CAPM results because his recommended common equity ratio of 45.0 percent for FEI would "significantly narrow the equity disparity with the gas proxy group."[723] The Panel agrees that any deviation from a 45.0 percent equity thickness, for example, setting FEI's equity thickness at the 40.0 percent to 42.0 percent range, may warrant a corresponding impact on the allowed ROE.

In the absence of contrary expert evidence and recognizing that FEI shareholder's real business risks, such as the impacts from the Energy Transition risk have increased since 2016, we accept Mr. Coyne's recommended 45.0 percent equity thickness for FEI. The Panel finds that the 45.0 percent equity thickness meets the comparable investment and capital attraction requirements in the Fair Return Standard because 45.0 percent is premised on FEI's proxy group and supported by our assessment of FEI's business risk. Further, as compared to FEI's current 38.5 percent equity thickness, an increase to 45.0 percent will maintain FEI's financial integrity.

The Panel now turns to financial leverage and financial flexibility. The Hamada adjustment and financial flexibility are partially related. The objective is to harmonize FEI and FBC's financial leverage to be comparable with peer proxy companies. For FEI, we acknowledge that 45.0 percent meets the Fair Return Standard and is supported by business risk assessment, comparable investments, and expert recommendation. In our view, a 45.0 percent equity component forms an optimal capital structure based on the evidence in Stage 1.

Further, since FortisBC's own expert acknowledges that 45.0 percent would "significantly narrow" the equity disparity and bring FEI's equity thickness towards the 50.0 percent to 52.0 percent range applicable to its proxy group, the Panel is not persuaded that increasing FEI's equity thickness beyond 45.0 percent to incorporate a further adjustment for financial flexibility or ring-fencing is required in order to meet the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FEI is 45.0 percent.**

For FBC, we note that FortisBC's proposed 40.0 percent equity thickness and interveners' positions are mostly aligned. Mr. Coyne also recommends 40.0 percent equity thickness for FBC. However, ICG submits that the BCUC should set FBC's equity thickness at 38.5 percent, which is based on the Canadian Electric median of 38.75 percent and submits that FBC's business risks are lower since 2013.[724] The Panel agrees with FortisBC that ICG's final arguments are unclear because on one hand, ICG submits that "the BCUC should place the greatest weight on the North American proxy group results"[725] but on the other hand, "the US proxy group should be no weight when determining FBC's equity ratio."[726] Therefore, we place no weight on ICG's recommendation to set FBC's deemed equity thickness at 38.5 percent.

As discussed in Section 4.3, the Panel finds that FBC's business risk overall has not changed materially since 2013. The Panel views that business risk assessment of FBC should be the primary factor to the determination of a fair capital structure. This is because we see that financial impacts, in part, result from our decision on the deemed capital structure. FBC has managed to maintain its current credit rating since 2013 at 40.0 percent equity thickness. Therefore, we find that no change in FBC's equity component within its current capital structure is warranted to reflect no material changes in its business risk.

Notwithstanding these findings, the Panel now needs to consider financial leverage and financial flexibility for FBC to determine whether any upward adjustment to its 40.0 percent equity thickness is warranted. FortisBC

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[723] FortisBC Reply Argument, p. 43.
[724] ICG Final Argument, pp. 3–4.
[725] Ibid., p. 10.
[726] Ibid., p. 16.

and Mr. Coyne are not recommending any capital structure changes for FBC and have not explicitly recommended a size premium in the CAPM analysis for FBC.

While 40.0 percent equity thickness is in line with the Canadian electric utility average of 39.42 percent, it is much lower than the US electric proxy group average of 49.76 percent. We accept Mr. Coyne's observation that his FBC recommendation is in line with FBC's current risk profile, but not within the range of its US peers. In light of our decision to consider financial leverage and financial flexibility in the capital structure, we find that a modest upward adjustment in equity thickness of 1.0 percent for FBC is warranted to conform with the Fair Return Standard. Therefore, **the Panel determines that the deemed equity component for FBC is 41.0 percent.**

Return on Equity

The Panel is persuaded by Dr. Lesser's view that, in addition to being anchored in financial theory and being transparent, models used by regulators to set the cost of capital for regulated utilities should ideally minimize reliance on subjective factors. Dr. Lesser states that 'subjective' adjustments to model results are those made without any underlying basis in financial theory and no empirical support, and he advises against these types of adjustments, as they can undermine confidence that the resulting allowed ROE values are 1) just and reasonable and 2) consistent with reasonable decision-making.

Previously in this decision, the Panel made certain determinations that are departures from, namely the 2013 and 2016 BCUC cost of capital decisions. One change worth highlighting is the Panel's determination to use North American proxy groups, based on a finding that using North American data, consisting of a reasonable mix of both Canadian and US comparators, is superior to using either Canadian proxy groups or US proxy groups alone.

Furthermore, the Panel accepts Mr. Coyne's beta estimates, which are Blume-adjusted, noting that both experts in this proceeding favour the use of Blume-adjusted betas and that none of the parties object to their use. The Panel is also reassured to see that empirical evidence exists to show that the Blume adjustment is applicable to all betas, ranging from a low of 0.50 to a high of 1.53. The Panel recognizes that the use of Blume-adjusted betas is a departure from the previous two BCUC cost of capital decisions and has the effect of increasing the CAPM ROE as the Blume-adjusted betas for Mr. Coyne's North American proxy group average 0.86, compared to a BCUC-accepted beta of 0.60 in the 2013 and 2016 Decisions.

Also, the Panel finds that it is appropriate to consider forward-looking estimates in determining the MRP and to base that forward-looking MRP on the Constant DCF model, which has been given equal weighting to the historical MRP. These determinations are also departures from previous BCUC decisions. In particular, the 2016 Decision placed more weight on historical MRP estimates than on the forward-looking ones and no weight on the DCF estimates of the forward-looking MRP (constant growth or Multi-Stage DCF). The Panel acknowledges that these determinations also increase the CAPM ROE relative to placing more weight on historical MRP or to using the Multi-Stage DCF model to estimate the forward-looking MRP.

Beyond these findings, the Panel takes the approach of making determinations that have a sound basis in financial theory, that are transparent and easily replicated, with minimal 'subjective' adjustments. The Panel agrees with Dr. Lesser and finds it preferable to get the allowed ROE value right based on the models rather than adjusting the allowed ROE after the fact, such as adding adders for financial flexibility and flotation costs or considering other adjustments as suggested by some interveners.

To balance the fact that pure market-based models like the DCF model and CAPM tend to get whipsawed by volatile conditions in the market, which characterized much of the period during which evidence was filed in this proceeding, the Panel finds that relying on more models than just the CAPM and Multi-Stage DCF is especially important. Accordingly, the Panel determined earlier in this decision that considerable weight should also be given to the use of the Risk Premium Model, instead of simply using it as a reasonableness check as Mr. Coyne advocates.

Ultimately, the Panel finds that assigning an equal weighting to each of the three models is appropriate for the following reasons: 1) the Panel sees merit in all three models, recognizing their respective strengths and weaknesses, and behaviour under different market conditions; 2) the Panel would be hard pressed to say that one model is fundamentally superior to the others; and 3) the Panel sees no compelling reason to give anything other than equal weighting to each of the three models.

The following table summarizes the Panel's previous individual determinations related to the ROE estimates based on the CAPM, Multi-Stage DCF model, Risk Premium Model, and the flotation costs and financial flexibility adders to arrive at its ROE determination for FEI and FBC, respectively.

Table 40: Allowed ROE for FEI and FBC

Models	Revised North American Gas Proxy Group	Revised North American Electric Proxy Group
CAPM – excluding flotation costs and financial flexibility adder (see Section 5.2.5)	9.90%	9.77%
Multi-Stage DCF model – excluding flotation costs and financial flexibility adder (see Section 5.3.3)	8.93%	8.99%
Flotation costs and financial flexibility adders for the CAPM and Multi-Stage DCF models only (see Section 6.2)	0.00%	0.00%
Risk Premium Model (see Section 5.4.3)	10.12%	10.16%
Average of all three models	**9.65%**	**9.64%**

From a purely mathematical standpoint, FEI would have an allowed ROE that is 1 bps higher than FBC. However, the Panel does not view that such differentiation in allowed ROE is warranted. The difference in utility characteristics is already reflected in the deemed capital structure for FEI and FBC. **The Panel finds that an allowed ROE of 9.65 percent for each of FEI and FBC will meet the Fair Return Standard based on the evidence examined and submissions received in Stage 1.**

For the reasons stated above, the Panel determines the following:

- **For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and**
- **For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.**

Although the allowed ROEs for both utilities are determined to be the same for FEI and FBC, the Panel notes that the reasoning behind the utilities' overall cost of capital determinations are fundamentally different. As a natural gas distribution utility, FEI's shareholder and investors are faced with higher business risk driven primarily by the Energy Transition. Hence, FEI's deemed equity component is higher than that of FBC. In contrast, while the Panel finds that FBC's business risks are similar since it was last reviewed, FBC is a relatively small utility with weaker financial metrics. Lastly, the financial models using the most recent October 2022 data and the appropriate proxy groups yielded very similar ROE results for both FEI and FBC.

FortisBC and Mr. Coyne introduce the weighted ROE concept, and the table below is a compilation of weighted ROEs presented by the parties compared to the Panel's decision.

Table 41: Comparison of Weighted ROEs for FEI and FBC

	FEI	FBC
Existing	3.37%	3.66%
Proposed	4.55%	4.00%
Canadian Average	3.23%	3.45%
U.S. Average	4.93%	4.72%
Proposed by interveners	3.20-3.99%	3.20-3.82%
Decision	9.65% * 45.0% = 4.34%	9.65% * 41.0% = 3.96%

Our decision falls within the range between the Canadian and US averages, as well as almost exactly halfway between the high-end of the interveners' recommendations and FortisBC's proposal. As explained in the reasons above, we find that the deemed equity thickness and allowed ROEs for each of FEI and FBC meet the Fair Return Standard. The Panel expects that our decision will fairly compensate investors' opportunity cost, maintain financial integrity of the utilities, and enable each utility to continue to attract new capital upon reasonable terms.

7.0 EFFECTIVE DATES AND STAGE 2 OF THE GCOC PROCEEDING

Having made our determinations on FEI and FBC's respective cost of capital, we now examine the appropriate timeline for the changes to come into effect. FEI and FBC currently have interim rates in place, effective January 1, 2023.[727] The BCUC invited parties to address the following:[728]

1. The effective dates for which FEI and FBC's cost of capital will take effect and the rationale; and
2. The timing and process to commence Stage 2.

The BCUC also invited further submissions on the effective date for all other utilities that use the Benchmark Utility to set their own cost of capital.[729]

[727] FEI Annual Review for 2023 Delivery Rates, Decision and Order G-352-22 dated December 5, 2022; FBC Application for Reconsideration and Variance of Order G-382-22, Decision and Order G-87-23 dated April 19, 2023.
[728] Exhibit A-26.
[729] Exhibit A-31.

FEI is the current benchmark (Benchmark Utility) for other utilities in BC that use a Benchmark Utility to set rates. In the April 2022 procedural conference, PNG, Corix, and RDE submitted that the choice of a Benchmark Utility is better addressed in Stage 2, after the BCUC determines FEI and FBC's cost of capital in Stage 1.[730]

As previously determined, in Stage 2, the Panel will consider, amongst other matters, whether FEI remains the appropriate default Benchmark Utility for some or all other utilities in BC, whether FBC is a more appropriate benchmark, or whether each utility's allowed ROE and deemed capital structure should be individually determined.

We summarize the parties' submissions below on the two issues identified above.

Positions of the Parties

Effective Dates for FEI and FBC

For FEI and FBC's cost of capital effective date, most parties support an effective date of January 1, 2023. FortisBC submits that January 1, 2023, reflects the evidence based on mid-2021 and December 2022 data of when the cost of capital analysis took place. Further, January 1, 2023, reflects current investor expectations based on recent data and would not delay the implementation on the utilities' right to earn a fair return.[731] Similarly, the CEC submits that January 1, 2023, would provide "equitable relief for FEI and other utilities as soon as possible" and "implementation can be factored into customer bills… to avoid having a larger catch-up."[732] ICG and RCIA also support the January 1, 2023 effective date.[733]

Nelson Hydro strongly disagrees with an effective date of January 1, 2023, and is "opposed to any retroactive rate increase for FBC,"[734] but does not propose a specific date other than "subsequent to a decision being made by the Panel." [735]

In response to Nelson Hydro, FortisBC states that the "January 1, 2023 implementation date is not "retroactive" in the legal sense, as FBC's rates are currently interim."[736] FortisBC argues that Nelson Hydro's approach "would contravene the Fair Return Standard"[737] and that the "legally permissible solution" is for Nelson Hydro to request approval for a deferral account (to capture the impacts of the change to FBC's cost of capital for 2023 on energy costs for recovery).[738]

730 Order G-106-22, Reasons for Decision, p. 4.
731 FortisBC Final Argument, p. 199.
732 The CEC Final Argument, p. 60.
733 ICG Final Argument, p. 18; RCIA Final Argument, p. 33.
734 Nelson Hydro Final Argument, p. 1.
735 Ibid., p. 2.
736 FortisBC Reply Argument, p. 84.
737 Ibid.
738 Ibid.

Timing and Process to Commence Stage 2

FAES suggests commencing Stage 2 at a minimum of 60 days following the BCUC's issuance of this GCOC Stage 1 Decision. [739] At the time of its January 2023 final arguments, Nelson Hydro submits that the appropriate commencement of Stage 2 is summer of 2023 when it has more capacity available to participate. [740]
The CEC recommends scheduling Stage 2 "as quickly as possible so that implementations [sic] for all utilities can be done this year with smooth implementations [sic]."[741]

Effective Dates for Utilities that Use the Benchmark Utility to Set Rates

Stage 2 is expected to examine the cost of capital for all other utilities such as PNG, Corix, Creative Energy, Nelson Hydro, RDE, FAES, and others, with the exception of BC Hydro. The Panel discusses AMPC's submissions with respect to the latter in Section 8.3 of our decision.

Utilities and interveners submit that the BCUC should avoid retroactive ratemaking as a matter of regulatory principle.[742] Submissions regarding the mechanisms to implement any rate changes varied, ranging between the use of interim rates, deferral accounts, compliance filing for updates, or aligning all utilities' effective dates to be the same. For instance, Corix submits that if the BCUC sets the Benchmark Utility's cost of capital, effective January 1, 2023, then the effective date for other utilities that uses the Benchmark Utility should be:[743]

1. January 1, 2023 for utilities that have interim rates in place, effective January 1, 2023;
2. The first day of the month following GCOC Stage 1 Decision's issuance for utilities that do not have interim rates but have an existing deferral account that can be used to absorb the impact of the change in ROE or capital structure; or January 1, 2024.

Corix also submits that regardless of the FEI effective date, each utility can submit compliance filings to the BCUC seeking approval or acceptance depending on their specific circumstances to update their tariffs and implement rate changes as required.[744] RDE is of a similar view, advocating for the opportunity to submit a compliance filing.[745]

FAES notes that the use of the Benchmark Utility for rate setting is "inherently designed to facilitate automatic changing of the rates of return for those utilities if the BCUC approves a change in the Benchmark Utility."[746] The CEC submits that to the extent that the BCUC issues a decision for FEI or FBC, effective either January 1, 2023 or January 1, 2024, prior to the completion of Stage 2, then the utilities relying on the existing Benchmark should be similarly adjusted on January 1, 2023 or January 1, 2024, respectively.[747] Creative Energy submits that the appropriate effective date to make changes for utilities using the Benchmark Utility should be consistent with

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[739] FAES Final Argument, p. 1.
[740] Nelson Hydro Final Argument, p. 2.
[741] The CEC Final Argument, p. 60; the CEC Submission dated May 31, 2023.
[742] RCIA Submission dated May 31, 2023, p. 1, BCOAPO Submission dated May 31, 2023, p. 1, Corix Submission dated May 31, 2023, p. 2.
[743] Corix Submission dated May 31, 2023, pp. 1–2.
[744] Corix Submission dated May 31, 2023, p. 3.
[745] RDE Submission dated May 31, 2023, p. 2.
[746] FAES Submission dated May 31, 2023, p. 3.
[747] The CEC Submission dated May 31, 2023, p. 1.

the date approved for FEI. The changes to rates should be made as soon as reasonably practical.[748] Nelson Hydro reiterates that FBC should not be permitted to utilize an effective date of January 1, 2023, for any changes to its cost of capital and that no changes should are warranted until the completion of the Stage 2. It submits that the fair and efficient implementation of rates for all utilities and their ratepayers should take place on a prospective basis only.[749]

With the implementation options available, utilities and interveners consider ratepayer impacts and the practicality of implementing rate changes. RCIA submits that implementing changes, effective January 1, 2024, allows for a more reasonable transition period and provides utilities and ratepayers more time to adapt to any changes.[750] PNG submits that implementing rate changes, effective January 1, 2024, will allow the other utilities to establish permanent rates for 2023. This provides rate stability and certainty for 2023 and will minimize rate impacts and amounts to be recovered from/refunded to ratepayers in the future.[751] PNG also argues that first applying other utilities' existing risk adjustments to FEI's new capital structure and ROE, and then applying the other utilities' new risk adjustment to the identified Benchmark Utility (or Utilities) will be administratively cumbersome and may cause unnecessary rate volatility for customers.[752] Similarly, RDE views that establishing new customer rates upon conclusion of Stage 1 will add significant regulatory burden and introduce inefficiency to the rate-setting process.[753] In contrast, Corix submits that delaying the implementation of changes until the completion of Stage 2 has a compounding effect and could result in a larger rate increase for customers as opposed to two smaller rate increases.[754]

FAES notes that the utilities and interveners propose a wide variety of opinions which reflect the unique characteristics of each utility. FAES submits that rate changes for each affected utility should occur independently according to their specific circumstances.[755]

Panel Determination

Effective Dates for FEI and FBC

The Panel agrees with FortisBC that the effective date for FEI and FBC's cost of capital should reflect the evidence examined throughout Stage 1. We note that the evidentiary record closed in December 2022. FEI and FBC already have interim rates as of January 1, 2023, in place awaiting the results of Stage 1. Thus, the earliest possible date to implement FEI and FBC's new cost of capital is January 1, 2023. We find that the effective date to implement changes should align with the period in which the evidence was examined to allow FortisBC to earn a fair return, and the date that best reflects the currency of that evidence is January 1, 2023.

The Panel acknowledges Nelson Hydro's opposition to implementing rate changes for FBC's cost of capital, effective January 1, 2023, on the basis that all utilities should implement rate changes on a prospective basis

[748] Creative Energy Submission dated May 31, 2023, p. 1.
[749] Nelson Hydro Submission dated May 31, 2023, pp. 1–2.
[750] RCIA Submission dated May 23, 2023, p. 1.
[751] PNG Submission dated May 31, 2023, p. 2.
[752] Ibid., p. 3.
[753] RDE Submission dated May 31, 2023, p. 2.
[754] Corix Submission dated May 31, 2023, p. 4.
[755] FAES Response dated June 14, 2023, pp. 1–2.

only. The BCUC sets rates prospectively subject to certain exceptions[756] as acknowledged by the courts such as in the *ATCO Gas & Pipelines Ltd. V. v Alberta (Energy & Utilities Board)* Decision.[757] However, we note that the BCUC had previously contemplated the possibility of a January 1, 2023 effective date, pending the results of Stage 1 and had approved interim rates for the FortisBC utilities for 2023 in the event that the BCUC determined that such effective date is appropriate. Therefore, we are not persuaded that FortisBC's cost of capital implementation should be delayed to 2024.

The Panel determines that the deemed capital structure and allowed ROE for FEI and FBC as set out in Section 6.3 of this decision be implemented, effective January 1, 2023. **Each of FEI and FBC is directed to file, within 30 days of the date of this decision, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved**.

Effective Dates for Utilities that Use the Benchmark Utility to Set Rates

As for other utilities that uses the Benchmark Utility to set their rates, the Panel concurs with FAES that there is a wide variety of opinions presented. We understand that each utility has its own preferences, and some utilities are undergoing their own rate proceedings and are at different stages. We also knowledge that absent specific exceptions, retroactive ratemaking is not permissible as a matter of regulatory principle. Furthermore, it would be unfair for utilities to retrospectively collect or refund customer monies without an appropriate mechanism for doing so or without adequate notice to ratepayers. However, while each utility's situation may be unique, some balance must be factored in to ensure consistency and fair treatment amongst all utilities.

In terms of the specific mechanism, the Panel considers that the benefits of establishing interim rates for all other utilities that use a Benchmark Utility to set their capital structure and equity return outweigh other mechanisms. Setting interim rates for all other utilities, effective January 1, 2024, allows the BCUC to make any adjustments at the conclusion of Stage 2. Ratepayers will be provided adequate notice that the rates they pay in 2024 will be subject to any changes resulting from Stage 2.

In the absence of notice to affected ratepayers of potential rate changes in 2023 arising from the BCUC's determinations in Stage 1, we are not persuaded that some utilities that already have interim rates in 2023 should be allowed to make rate adjustments in 2023, simply because they were granted interim rates, pending a final decision on permanent rates for each utility's respective rate proceedings. The same applies to some utilities that may already have regulatory deferral accounts that can capture timing differences in the allowed return.

Further, the establishment of any new deferral accounts can only capture differences on a prospective basis. In either case of using previously approved interim rates or deferral accounts, the Panel finds that customers are not given proper notice that the existing rates they are currently paying may change due to a pending GCOC decision. This is in direct contrast to FBC and FEI, which have flagged the issue of the effective date of the cost of capital throughout Stage 1 as a matter that required determination, and sought and received BCUC approval for interim 2023 rates during the utilities' Annual Review proceedings specifically for that purpose.

[756] For example, through interim rates or deferral accounts.
[757] Supreme Court of Canada, ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board), [2006] 1 S.C.R. 140, 2006 SCC 4 dated February 9, 2006, p. 179.

As for any automatic adjustments prior to and during Stage 2 due to changes to the Benchmark Utility's deemed capital structure and allowed ROE, the Panel agrees with RCIA, PNG and RDE that predictable rates and regulatory efficiency are important factors. Establishing interim rates, effective January 1, 2024, for all utilities that use the Benchmark Utility is just and reasonable. No adjustments are warranted to backdate a utility's earned return to January 1, 2023, or between the date of this GCOC Stage 1 Decision and January 1, 2024.

We also find that it would be inappropriate to increase other utilities' allowed ROE automatically based on their existing ROE premium in isolation, but without any consideration of their deemed capital structure. Further, we note PNG, Corix and RDE at the April 2022 procedural conference requested that the Benchmark Utility be determined after the outcome of Stage 1. Since then, no utilities have notified or requested of the BCUC in this proceeding that their rates be made interim in order to address the potential impacts of the BCUC's determinations on their rates in the various stages of the GCOC proceeding.

Therefore, the Panel directs that interim rates, effective January 1, 2024, be established on a refundable or recoverable basis for all other utilities that currently use the Benchmark Utility to set their capital structure and equity return, pending the BCUC's final decision on Stage 2. The BCUC will determine the manner by which any variance between approved interim rates and permanent rates, including interest if any, will be refunded or recovered at the time the BCUC renders its final decision on Stage 2.

For greater clarity, the interim rates to be established for utilities, effective January 1, 2024, do not apply to FBC, as its deemed capital structure and allowed ROE have been determined in Stage 1 and are effective January 1, 2023.

Timing and Process to Commence Stage 2

We agree with the CEC that Stage 2 should commence as soon as possible. FAES suggests that a minimum of 60 days following this GCOC Stage 1 Decision. Previous procedural orders established the scope of Stage 2.[758] Upon further review, the Panel amends item 1 by adding "neither" to reflect that no benchmark is also a plausible scenario.

PROCEEDING SCOPE – Stage 2

1. Whether the Benchmark Utility should be FEI, FBC, both, or neither. The groupings of public utilities for cost of capital determinations.

2. The establishment of the cost of capital for public utilities, or groups of public utilities, except for BC Hydro.

3. Whether any range or default in the equity component and equity risk premium is warranted for public utilities, or groups of public utilities.

4. Whether the determination of a deemed interest rate is warranted. If warranted, then:
    a) The circumstances where a deemed interest rate is required.

[758] Order G-106-22, Appendix C.

b) The determination of the deemed interest rate where required.

c) Whether an interest rate AAM is warranted.

d) The effective date for which the deemed interest rate or interest rate AAM will take effect.

5. Any items that may be identified during the proceeding to be considered in Stage 2. The Panel will communicate any additional items to participants.

The Panel remains of the view that the first step in Stage 2 is to address whether FEI should continue as the appropriate default Benchmark Utility for some or all other utilities in BC, whether FBC is a more appropriate benchmark, or whether each utility's allowed ROE and deemed capital structure should be individually determined. The BCUC has previously invited a round of submissions in June 2021.[759]

We acknowledge that utilities and interveners may wish to provide updated submissions given this GCOC Stage 1 Decision. However, recognizing that parties already have some background on the matter, we consider that an expedited regulatory timetable will help progress Stage 2 to examine and set the cost of capital for all other utilities in BC. Given this GCOC Stage 1 Decision, the Panel also invites parties to file submissions with respect to any appropriate modifications to the scope of Stage 2 that the BCUC previously established.

Therefore, the Panel confirms Stage 2 will commence 60 days after the date of this decision.

8.0 OTHER ISSUES

8.1 Automatic Adjustment Mechanism

The scope for GCOC Stage 1 as established by Order G-281-21 includes consideration of the potential reinstatement of an AAM formula as part of the ROE. [760] If the re-establishment of the ROE AAM formula is warranted, then the Panel must determine: (a) the specifications of the ROE AAM formula; (b) the frequency with which the ROE AAM formula will apply (i.e. annually or some other frequency) and the entities to which the AAM will apply; and (c) the date for which the ROE AAM formula will take effect.[761]
An AAM represents a formulaic approach to setting the ROE of the Benchmark Utility annually between ROE proceedings.[762]

In 1994, the BCUC first implemented an AAM based on changes to long-term Canada bond rates,[763] which underwent various changes and iterations[764] until 2009 when it was eliminated. That elimination was based on the BCUC's determination at that time that the AAM would not have provided an ROE that met the Fair Return Standard.[765]

[759] Order G-183-21.
[760] Exhibit A-8, Appendix B to BCUC Order G-281-21, p. 1 of 2.
[761] Ibid.
[762] BCUC 2013 GCOC Stage 1, Letter L-53-13, Appendix A, p. 1.
[763] In the Matter of Return on Common Equity – BC Gas Utility Ltd., Pacific Northern Gas Ltd., West Kootenay Power Ltd. -- Decision and Order G-35-94, June 10, 1994.
[764] Exhibit B1-8, Table 9-1, p. 57.
[765] Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., and Return on Equity and Capital Structure (2009 TGI ROE), Decision to Order G-158-09, p. 72.

In 2013, the AAM was re-instituted on the basis that it offered the potential for regulatory efficiency and would better meet the Fair Return Standard than giving no consideration to market changes over the period between ROE proceedings.[766] The BCUC established a two-variable model taking into account utility bond spreads, as well as long-term Canada Bond yields.[767] However, in recognition of the effect of monetary policy on bond rates, the BCUC directed any implementation of the AAM be subject to an actual long-term Canada bond yield of 3.8 percent being met or exceeded (estimate of 3.8 percent was deemed reasonable by the BCUC and was within the relatively narrow range of estimates presented by all experts).[768] Therefore, the AAM formula would only apply if the long Canada bond yield was above 3.8 percent.[769]

In 2016, the BCUC suspended further use of an AAM as a mechanism to adjust ROE on an annual basis, as the BCUC was not persuaded that the AAM was appropriate given “uncertain” economic conditions, nor would it necessarily result in an ROE that would meet the Fair Return Standard given it does not reflect all items that affect a utility’s ROE.[770] Nonetheless, BCUC indicated that it continued to hold the view that an effective AAM can be a useful tool in providing an updating mechanism for ROE, as this would eliminate some of the need for lengthy and expensive formal reviews. The BCUC suggested that once there is a return to more certain economic conditions with more normal interest rates, re-implementation of an AAM would be worthy of further consideration.[771]

In the current proceeding, FortisBC notes various drawbacks of the AAM: (i) it is not guaranteed to result in regulatory efficiency; (ii) it does not capture all factors that affect a utility’s cost of capital such as an individual company’s financial and business risk, proxy companies’ earnings growth, and beta values; and (iii) the AAM formula is based on historical relationships that are not guaranteed to hold in future years, especially in uncertain capital markets.[772] Consistent with previous proceedings, FortisBC believes that an AAM formula cannot capture all of the changes facing a utility's cost of capital and it can yield a return that does not meet the Fair Return Standard.[773] FortisBC notes this is particularly true in the current economy where monetary and fiscal policies in response to the COVID-19 pandemic have resulted in significant uncertainty in capital markets that do not reflect the historical relationship between interest rates and equity returns.[774]

Mr. Coyne submits that the two-variable AAM formula from the 2013 GCOC proceeding is limited to changes in government bond yields and utility credit spreads, which are not the only relevant factors in determining the cost of equity for regulated utilities.[775] He further notes that the two-variable AAM formula from the 2013 GCOC proceeding would not reflect changes in other factors such as company size, fuel source, scope and business risk profile.[776] Mr. Coyne notes that he is not aware of an ROE formula that considers or adjusts for changes in capital structure; the capital structure remains fixed until the next full rate case.[777] Mr. Coyne performed a

[766] 2013 Decision, p. 88.
[767] Ibid., p. 90.
[768] Ibid., p. 91.
[769] Ibid.
[770] 2016 Decision, p. 89.
[771] 2016 Decision, p. 89.
[772] Exhibit B1-8, Section 9.2, pp. 58–61.
[773] Ibid., p. 60.
[774] Exhibit B1-8, Section 9.2, pp. 60–61, Exhibit B1-9, BCUC IR 61.2.
[775] Exhibit B1-9, BCUC IR 61.1.
[776] Ibid.
[777] Exhibit B1-9, BCUC IR 61.4.

jurisdictional review which indicates that AAMs are no longer a common approach in Canada.[778] Mr. Coyne concludes that periodic rate hearings remain the only reliable method for determination of utility ROEs given that all formulaic approaches run the risk of deviation from a fair return.[779] Mr. Coyne does note that if the BCUC were to determine that an AAM is appropriate, he would recommend that the BCUC establish an additional process to determine the correct formula given that developing an adjustment formula is a very detailed process that is better accomplished through input from regulated utilities and stakeholders.[780]

Dr. Lesser notes the greatest strength of the AAM is its simplicity. Dr. Lesser also notes certain weaknesses of the AAM, including (i) this same simplicity may not meet the Fair Return Standard and does not reflect other changes that affect cost of capital; and (ii) the degree of subjectivity required in determining the functional form of the AAM.[781]

FortisBC notes that bond spreads are still below the 3.8 percent trigger point in the previous AAM, which was implemented by the BCUC to recognize the potential for downward bias in ROE results when bond spreads are low.[782] FortisBC submits that there is little benefit in approving an AAM in the current proceeding due to the uncertainty of its applicability.[783] FortisBC concludes that the BCUC should continue to use periodic regulatory proceedings to set ROE, rather than implementing an AAM.[784]

Positions of the Parties

Interveners offer differing views. RCIA supports the introduction of an AAM in the current proceeding, the CEC supports the introduction of an AAM in the current proceeding but in the second stage, BCOAPO supports the concept of an AAM but not the introduction of one in the current proceeding, and ICG does not support an AAM.[785]

RCIA supports the use of an AAM, disagreeing with FortisBC.[786] RCIA states that the AAM developed by the BCUC in 2013 is akin to the basic CAPM and incorporates changes in the underlying risk-free rate to calculate the premium above the risk-free rate a utility would need to meet the Fair Return Standard.[787] RCIA cites Mr. Coyne's statements that based upon the bond yield alone, the regression model predicts 86 percent and 82 percent of the variance in approved ROE in Canada and the US, respectively.[788] RCIA states that the CAPM is a relatively simple model with only three input parameters (risk-free rate, market risk premium, and beta) producing highly reliable results.[789] Therefore, RCIA submits it is viable to re-establish a CAPM-type AAM that reliably and efficiently meets the Fair Return Standard within the next two to four years, and supports using the

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778 Exhibit B1-8-1, Appendix C, Concentric Report, pp. 153–154, Exhibit 1-9, BCUC IR 61.6–61.10.
779 Exhibit B1-8-1, Appendix C, Concentric Report, p. 154.
780 Exhibit B1-9, BCUC IR 61.6–61.10.
781 Exhibit A2-3, Lesser Report, p. 92.
782 FortisBC Final Argument, p. 198.
783 FortisBC Final Argument, p. 198.
784 Ibid., p. 197.
785 RCIA Final Argument, pp. 32–33, The CEC Final Argument, pp. 59–60, BCOAPO Final Argument, pp. 71–72, ICG Final Argument, pp. 17–18.
786 RCIA Final Argument, p. 33.
787 Ibid.
788 Ibid.
789 Ibid.

previously approved 2013 formula for any interim period prior to the next GCOC hearing.[790] Furthermore, RCIA recommends that the benchmark ROE calculated by the AAM, with annual updates, apply to all utilities, with differences in utility risk profiles being addressed through bespoke equity thicknesses for each utility.[791] RCIA also submits that the reintroduction of the AAM in BC is appropriate to facilitate regulatory efficiency.[792]

The CEC states that the Risk Premium Model demonstrates a high degree of correlation between the changes in government bond rates and the appropriate ROE for utilities.[793] The CEC submits that it would be appropriate for the BCUC to direct a move toward establishing an AAM for the ROE estimates for FEI, which can then enable adjustments to all BC utilities[794] and provide regulatory efficiency, simplicity, and understandability. [795] The CEC submits that a simple straight-line formula through the historical data will establish a reasonable basis for adjusting components of the basis for establishing the ROEs for utilities.[796] The CEC recommends that where it had previously established economic and financial conditions with respect to bond prices that would not work as well with a straight-line formula, the BCUC should solicit further input with respect to a formula at the tail which could suitably accommodate a very low bond rate with a bend in the straight-line curve.[797] The CEC recommends setting a trigger amount for implementing a change if the risk premium falls outside of the straight-line formula by more than a fixed number of basis points (say 20 bps) to avoid minor changes that would not be material for FEI's financial standing in the capital markets. [798]

The CEC also recommends that the BCUC task FEI with reporting requirements and makes suggestions on the review process. The CEC recommends that the BCUC task FEI with establishing the formulas for review as a compliance requirement[799] and also task FEI to review the AAM with its credit rating agencies so that the BCUC can consider both the formula and the credit rating agency view.[800] With respect to process, the CEC submits that the BCUC could use a simple annual streamlined review process to review the implementation with the utilities and interveners before finalizing the implementation through FEI.[801] The CEC recommends an annual review process so that the need to implement a change is not too frequent. [802]

BCOAPO continues to support the use of an AAM but it does acknowledge the previous BCUC concerns about the difficulty establishing such a mechanism when economic conditions are uncertain and the evidence in this proceeding is clear: current economic and capital market conditions are both uncertain and volatile.[803] As result, BCOAPO accepts that now is not likely the appropriate time to attempt to design and implement an AAM.[804]

[790] RCIA Final Argument, p. 33.
[791] Ibid., pp. 32–33.
[792] Ibid., p. 32.
[793] The CEC Final Argument, p. 59.
[794] Ibid.
[795] Ibid.
[796] Ibid.
[797] The CEC Final Argument, p. 60.
[798] Ibid.
[799] Ibid., p. 59.
[800] Ibid.
[801] Ibid.
[802] Ibid., p. 60.
[803] BCOAPO Final Argument, pp. 71–72.
[804] Ibid.

ICG does not support an AAM.[805] ICG cites Dr. Lesser's statements that if an AAM is used to adjust the allowed ROE for the benchmark, then the risk adjustments for the other utilities may need to be adjusted.[806]

In response to RCIA, FortisBC notes that RCIA's suggestion to update the 2013 AAM as soon as reasonably possible is inconsistent with the 2016 Decision that suspended further use of an AAM in part due to economic uncertainty.[807] FortisBC notes that the conditions of economic uncertainty noted in 2016 continue to be a relevant consideration in the current proceeding that RCIA did not address in its final argument.[808]

FortisBC also states that the RCIA is incorrect in stating that the 2013 AAM is no less sophisticated than the models presented by FortisBC.[809] FortisBC asserts that Mr. Coyne's analysis contains multiple models and is in no way akin to the output of the 2013 AAM which is a two-variable model, based on long Canada bond yields and the spread between long Canada bonds and A-rated utility corporate bonds.[810]

In response to the CEC, FortisBC notes that there is little utility in examining an AAM in the current period of high inflation and economic uncertainty.[811] FortisBC submits that attempts to mechanize the cost of capital may lead to ROE values that do not meet the Fair Return Standard, particularly in uncertain market conditions.[812] However, FortisBC notes that should the BCUC determine that the reintroduction of an AAM warrants consideration at this time, FortisBC agrees with the CEC that it would be more appropriately considered in a further stage.[813]

Panel Discussion

The Panel supports the BCUC's determination in the 2016 Decision that suspended further use of an AAM in part due to economic uncertainty.[814] As noted by FortisBC, the conditions of economic uncertainty observed in 2016 continue to be a relevant consideration in the current proceeding. The Panel shares the BCUC's concerns about the appropriateness of using AAM in "uncertain" economic conditions. When coupled with the current high inflationary environment, there is a real potential for an AAM to fail to meet the Fair Return Standard since it does not reflect all items that could potentially affect a utility's ROE.

As observed historically, the use of an AAM in an ultra-low interest rate environment is complex. While the current interest-rate environment may not be characterized as ultra-low, the reinstatement of an AAM would nonetheless entail a review and potential resetting of the previously BCUC-approved 3.8 percent interest rate threshold. As no party has offered any evidence with respect to the latter issue in this proceeding, we would have to reopen the evidentiary record in order to obtain evidence and submissions on this, which would result in a delay which we consider unwarranted in view of the length of this proceeding to date.

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805 ICG Final Argument, p. 17.
806 Ibid., pp. 17–18.
807 FortisBC Reply Argument, pp. 80–81.
808 Ibid.
809 Ibid., p. 81.
810 Ibid., p. 81.
811 FortisBC Reply Argument, p. 80.
812 Ibid.
813 Ibid.
814 Ibid., pp. 80–81.

We also note that while the previous AAM was based on changes in interest rates, ROE can be impacted by many other factors beyond interest rates. As Dr. Lesser cautions, the simplicity of an AAM fails to address other changes that affect cost of capital, depends on the subjectivity in establishing an appropriate formula, and risks not achieving the Fair Return Standard. Overall, we find that any regulatory efficiency that can be gained from the application of an AAM formula to avoid another full scale review of ROE is offset by these weaknesses. Furthermore, the latter has the benefit of providing parties with the opportunity to engage in a more transparent and thorough review of ROE whenever changes are required to reflect new circumstances.

Accordingly, we decline to reinstate the application of an AAM formula in favour of periodic regulatory reviews to set ROE, which we consider to be a better forum for ensuring that a utility's ROE meets the Fair Return Standard than reliance on a formula which 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 application in this proceeding.

8.2 Off-Ramp / Trigger for Future Applications

The scope of Stage 1 includes consideration of "[t]he criteria, off-ramps, or other triggers to warrant a future cost of capital proceeding."[815]
FortisBC submits that the BCUC should not establish a trigger in advance.[816] FortisBC is unaware of any regulator that considers pre-defined triggers or criteria for future applications.[817] There are various factors that can impact investors' opportunity cost. Mr. Coyne submits that periodic cost of capital proceedings every three to five years is the best approach to ensure that the authorized return remains appropriate for regulated utilities, including those in BC.[818]

Positions of the Parties

FortisBC submits that a periodic review is appropriate and that there should be no establishment of a trigger, as there is no basis to rely on the variance between realized and allowed ROEs to initiate a cost of capital proceeding.[819]

In contrast, the CEC recommends a trigger for another GCOC proceeding in the event that any utility notifies the BCUC of "conditions that would impact its credit ratings" and establishes evidence that it is "seriously compromised in efforts to obtain needed capital."[820] Furthermore, the CEC recommends that triggering another GCOC proceeding may become "unnecessary for an indefinite time into the future provided the Commission enables processes for modifications to the AAM process that may be considered annually as improvements to the initially defined AAM," which it submits to be "a direct solution."[821] In reply, FortisBC agrees with CEC's recommendation that it should be open at all times for a Benchmark Utility to approach the BCUC with a justified request for a new GCOC and complete overhaul of the cost of capital regime, including the need to discard an AAM that cannot be suitably adjusted to deliver a fair return.[822]

[815] Order G-106-22 dated April 21, 2022.
[816] Exhibit B1-8, p. 62.
[817] Ibid., p. 7.
[818] Exhibit B1-8, p. 62, Exhibit B1-8-1, Appendix C, p. 156.
[819] FortisBC Final Argument, pp. 198–199.
[820] The CEC Final Argument, p. 60.
[821] Ibid.
[822] FortisBC Reply Argument, p. 82.

BCOAPO submits that if appropriate triggers cannot be established then another cost of capital proceeding should be scheduled no later than in three years' time or the BCUC should, on a similar timeline, establish a regulatory process to determine whether economic and market conditions have changed sufficiently to warrant a full review.[823]

In response to BCOAPO, FortisBC argues that "the BCUC should not establish a trigger for future cost of capital proceedings in advance."[824] FortisBC emphasizes that maintaining flexibility over the timing of the next review allows for a more appropriate response to business and capital market factors affecting the cost of capital for utilities that are inherently dynamic.[825] Furthermore, FortisBC explains that "the three-year timeline that BCOAPO suggests is too short; the BCUC has generally considered FEI's cost of capital every five years."[826]

RCIA submits that the next GCOC proceeding should be deferred to 2025 or later, noting that the underlying assumptions and method approved in this proceeding are "unlikely to change in the short term."[827] In response to RCIA, FortisBC agrees "to the extent that it implies that another proceeding should not be currently scheduled for the immediate future." However, it emphasizes that "2025 would be too early for a further periodic review."[828] Similar to its response to BCOAPO, FortisBC also notes that the BCUC has generally considered FEI's cost of capital every five years.[829]

Panel Determination

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.

While the BCUC in the 2013 GCOC proceeding indicated that it would review FEI's cost of capital in three years, we do not see the need to be prescriptive in this instance about the timing of the next review. We note that in any event, both FEI and FBC are currently under a multi-year rate plan which includes an off-ramp which is designed as a safeguard to protect the utility and ratepayers against potential unintended consequences (such as windfall surplus or losses) and is triggered if earnings in any one year vary from the approved ROE by +/- 150 bps. That plan expires at the end of 2024 and if there are material changes to markets or economic conditions after that affecting the utilities' ROE, we anticipate that either the BCUC or the utility will initiate a review of any changes at that time.

That said, we view that periodic reviews of utilities' cost of capital are desirable in ensuring that utilities continue to have the opportunity to earn a fair return based on their ROE and cost of capital despite changes in circumstances. At the same time, we recognize that such reviews entail significant investments of time and effort on the part of participants and should not be undertaken except where warranted.

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823 BCOAPO Final Argument, p. 72.
824 FortisBC Reply Argument, p. 82.
825 Ibid., p. 83.
826 Ibid.
827 RCIA Final Argument, p. 34.
828 FortisBC Reply Argument, p. 82.
829 Ibid., p. 83.

As for determining specific triggers that would prompt a cost of capital review, we see no merit to doing so in the absence of any evidence or submissions from parties as to what may be appropriate objective triggers. We agree with FortisBC that maintaining overall flexibility over the timing of the next cost of capital review is desirable as a more appropriate response to dynamic market and business factors that are not always foreseeable. For the same reason, we do not consider it particularly helpful to limit the triggers for review to specific occurrences which are only at best speculative.

8.3 AMPC Request Regarding BC Hydro

AMPC represents members of BC Hydro's industrial customers and submits that shareholder return is one of the most important issues impacting electricity competitiveness in BC. When the BCUC invited submissions from parties regarding the effective date for all other utilities that use the Benchmark Utility to set their own cost of capital, AMPC took the opportunity to request the BCUC to determine that "if BC Hydro's forthcoming rate of return application is based on the benchmark utility it will be deemed incomplete and rejected pending evidence that considers BC Hydro's full context as an instrument of government policy."[830]

In reply, BC Hydro submits that it is procedurally unfair for AMPC to request the BCUC to decide on BC Hydro's forthcoming cost of capital application before it is even filed. BC Hydro's cost of capital application should be considered by the panel appointed to that proceeding.[831]

Panel Discussion

We decline AMPC's request to make any determination on BC Hydro's future cost of capital application. The evidence presented before us in Stage 1 relates to setting FEI and FBC's respective capital structure and equity return, not BC Hydro or any other utility. The BCUC in its BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Decision directed BC Hydro to file a cost of capital application, effective April 1, 2025, by no later than April 1, 2024.[832] AMPC is encouraged to participate and share its views in that future proceeding.

9.0 SUMMARY OF DIRECTIVES

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

	Directive	**Page No.**
1.	The Panel finds that FEI's overall business risk has increased since 2016.	50

830 AMPC Submission dated May 31, 2023, pp. 1–2.
831 BC Hydro Response dated June 14, 2023, p. 2.
832 BC Hydro Fiscal 2023 to Fiscal 2025 Revenue Requirements Application, Decision and Order G-91-23 dated April 21, 2023, p. 10.

	Directive	**Page No.**
2.	The Panel finds that FBC's business risk overall has not changed materially since 2013.	63
3.	The Panel finds that an allowed ROE of 9.65 percent for each of FEI and FBC will meet the Fair Return Standard based on the evidence examined and submissions received in Stage 1.	136
4.	The Panel determines the following: • For FEI, a deemed equity component of 45.0 percent and an allowed ROE of 9.65 percent; and • For FBC, a deemed equity component of 41.0 percent and an allowed ROE of 9.65 percent.	136
5.	Each of FEI and FBC is directed to file, within 30 days of the date of this decision, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved.	141

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of September 2023.

Original signed by:

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D. M. Morton
Panel Chair / Commissioner

Original signed by:

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A. K. Fung, KC
Commissioner

Original signed by:

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K. A. Keilty
Commissioner

Original signed by:

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T. A. Loski
Commissioner

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ORDER NUMBER
G-236-23

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

and

British Columbia Utilities Commission
Generic Cost of Capital Proceeding

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

on September 5, 2023

ORDER

WHEREAS:

A. By Order G-66-21 dated March 8, 2021, pursuant to section 82 of the *Utilities Commission Act* (UCA), the British Columbia Utilities Commission (BCUC) established a Generic Cost of Capital (GCOC) proceeding;

B. By Orders G-66-21, G-156-21, G-183-21, G-205-21, G-231-21, G-281-21, G-288-21, G-106-22, G-217-22A, and G-327-22A, the BCUC established a regulatory timetable and scope for the GCOC proceeding;

C. The GCOC proceeding is being conducted in two stages. Stage 1 of the GCOC proceeding will determine the deemed capital structure and allowed return on equity (ROE) of FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively, FortisBC). Stage 2 will determine matters related to the Benchmark Utility and establish the cost of capital for other utilities in British Columbia;

D. The following parties participated in Stage 1 of the GCOC proceeding: FEI, FBC, Corix Multi Utility Services Inc. (Corix), Pacific Northern Gas Ltd. (PNG), River District Energy (RDE), British Columbia Hydro and Power Authority (BC Hydro), Boralex Ocean Falls Limited Partnership (Boralex), FortisBC Alternative Energy Service Inc. (FAES), Nelson Hydro, Kyuquot Power Ltd. (KPL), Creative Energy Vancouver Platforms Inc. (Creative Energy) Residential Consumer Intervener Association (RCIA), Movement of United Professionals (MoveUP), Clean Energy Association of BC (CEABC), Association of Major Power Customers of BC (AMPC), Industrial Customers Group (ICG), Commercial Energy Consumers Association of British Columbia (the CEC), and British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO);

E. The BCUC retained Dr. Jonathan A. Lesser of Continental Economics Inc. (Dr. Lesser) as an independent cost of capital technical expert in the GCOC proceeding. FortisBC retained Mr. James Coyne of Concentric Energy Advisors Inc. (Mr. Coyne) to provide an estimate of the cost of capital for FEI and FBC;

F. In its evidence dated January 31, 2022, pursuant to sections 59 to 61 of the UCA, FortisBC sought BCUC approval of the following:

   i. For FEI, approval of a capital structure consisting of 45 percent common equity and 55 percent debt, and a return on common equity of 10.1 percent.

   ii. For FBC, approval of a capital structure consisting of 40 percent common equity and 60 percent debt, and a return on common equity of 10.0 percent.

G. The regulatory review process for Stage 1 of the GCOC proceeding included two rounds of information requests (IRs) to FortisBC, one round of IRs to Dr. Lesser on Mr. Coyne's evidence, FortisBC rebuttal evidence on Dr. Lesser's IR responses, an oral hearing, final arguments, and further submissions regarding the implementation of utilities' rates; and

H. The BCUC has reviewed the submissions, evidence and arguments filed in Stage 1 of the GCOC proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 58 to 61 of the UCA, the BCUC orders as follows:

1. For FEI, the deemed equity component is 45.0 percent and the allowed ROE is 9.65 percent, effective January 1, 2023.

2. For FBC, the deemed equity component is 41.0 percent and the allowed ROE is 9.65 percent, effective January 1, 2023.

3. FEI and FBC are directed to file, within 30 days of the date of this order, a compliance filing for January 1, 2023 permanent rates, and if applicable, an evidentiary update for each utility's 2024 Annual Review proceedings to reflect and implement the deemed capital structure and allowed ROE as approved.

4. Interim rates are established, 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.

5. Stage 2 of the GCOC proceeding is to commence 60 days after the date of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 5th day of September 2023.

BY ORDER

Original signed by:

D.M. Morton
Commissioner

British Columbia Utilities Commission
Generic Cost of Capital Proceeding

GLOSSARY AND ARCRONYMS

2013 Decision	BCUC 2013 Generic Cost of Capital Stage 1, Order G-75-13 and Decision dated May 10, 2013
2014 Decision	BCUC 2013 Generic Cost of Capital, Order G-47-14 and Decision dated March 25, 2014
2016 Decision	FEI Application for its Common Equity Component and Return on Equity for 2016, Order G-129-16 and Decision dated August 10, 2016
AAM	Automatic Adjustment Mechanism
AMPC	Association of Major Power Customers of BC
AUC	Alberta Utilities Commission
BC	British Columbia
BC Hydro	British Columbia Hydro and Power Authority
BCOAPO	British Columbia Old Age Pensioners’ Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens’ Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society
BCUC	British Columbia Utilities Commission
BCUC 2013 GCOC proceeding	Collectively, Stage 1 and Stage 2 of the BCUC 2013 Generic Cost of Capital proceeding
Benchmark Utility	FortisBC Energy Inc. is the current benchmark for other utilities in BC that use a Benchmark Utility to set their rates
Boralex	Boralex Ocean Falls Limited Partnership
bps	Basis points
CAPM	Capital Asset Pricing Model
CEABC	Clean Energy Association of BC
COC	Cost of Capital
Concentric	Concentric Energy Advisors Inc.
Continental Economics	Continental Economics, Inc.
Corix	Corix Multi Utility Services Inc.
CPI	Consumer Price Index
Creative Energy	Creative Energy Vancouver Platforms Inc.
CRSP	Center for Research in Security Prices
DBRS	DBRS Morningstar, credit rating agency
DCF	Discounted cash flow
DPS	Dividend per share
Dr. Lesser	Dr. Jonathan A. Lesser of Continental Economics, Inc.
Dr. Lesser's Report	Regulated Utility Cost of Capital: Theory and Canadian Practice Report dated August 4, 2021, by Dr. Jonathan A. Lesser of Continental Economics, Inc.
EPS	Earnings per share
ESG	Environmental, social and governance
EV	Electric vehicle
FAES	FortisBC Alternative Energy Service Inc.
FBC	FortisBC Inc.
FEI	FortisBC Energy Inc.

FEI 2016 COC proceeding	FEI Application for its Common Equity Component and Return on Equity for 2016
FERC	Federal Energy Regulatory Commission
FortisBC	collectively, FEI and FBC
FortisBC's Evidence	Filing of evidence by FBC and FEI, including Evidence of Mr. James Coyne of Concentric Energy Advisors Inc.
FPIC	Free, prior and informed consent
GCOC	Generic Cost of Capital
GDP	Gross domestic product
IBES	Institutional Brokers' Estimate System
ICG	Industrial Customers Group
IR	Information Request
KPL	Kyuquot Power Ltd.
LNG	Liquefied natural gas
LTGRP	Long Term Gas Resource Plan
Moody's	Moody's Investors Service
MoveUP	Movement of United Professionals
Mr. Coyne	Mr. James Coyne of Concentric Energy Advisors Inc.
MRP	Market Risk Premium
MRS	Mandatory Reliability Standards
O&M	Operations and maintenance
PNG	Pacific Northern Gas Ltd.
RCIA	Residential Consumer Intervener Association
RDE	River District Energy
rf	the risk-free rate of return
rm	the required return for the market as a whole
Roadmap	CleanBC Roadmap to 2030
ROE	Return on Equity
S&P	Standard &Poor's Global Ratings
Stage 1	First stage of this GCOC proceeding
Stage 2	Second stage of this GCOC proceeding
The CEC	Commercial Energy Consumers Association of British Columbia
TSX	Toronto Stock Exchange
UCA	*Utilities Commission Act*
UPC	Use per customer
US	United States

APPENDIX B

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

and

British Columbia Utilities Commission
Generic Cost of Capital

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated January 18, 2021 – British Columbia Utilities Commission (BCUC) issuing Notice of Initiating a Generic Cost of Capital proceeding
A-2	Letter dated March 3, 2021 – BCUC appointing the panel for review of the BCUC's Generic Cost of Capital proceeding
A-3	Letter dated March 8, 2021 – BCUC Order G-66-21 establishing a regulatory timetable and public notice
A-4	Letter dated May 21, 2021 – BCUC Order G-156-21 with Reasons for Decision and establishing the proceeding's scope and a further regulatory timetable
A-5	Letter dated June 11, 2021 – BCUC Order G-183-21 with reasons for decision and a further regulatory timetable
A-6	Letter dated July 7, 2021 – BCUC Order G-205-21 with reasons for decision and amended scope.
A-7	Letter dated July 30, 2021 – BCUC Order G-231-21 with amended regulatory timetable
A-8	Letter dated September 24, 2021 – BCUC Order G-281-21 with Reasons for Decision amending the scope and regulatory timetable
A-9	Letter dated October 6, 2021 – BCUC Order G-288-21 amending regulatory timetable
A-10	Letter dated October 27, 2021 – BCUC response to Dr. Lesser extension request
A-11	Letter dated February 28, 2022 – BCUC Information Request No. 1 to FEI and FBC

Exhibit No.	Description
A-12	Letter dated March 31, 2022 – BCUC submitting procedural conference information
A-13	Letter dated April 21, 2022 – BCUC Order G-106-22 with Reasons for Decision amending the scope and regulatory timetable
A-14	Letter dated May 16, 2022 – BCUC Information Request No. 2 to FEI and FBC
A-15	Letter dated May 16, 2022 – BCUC Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
A-16	Letter dated May 20, 2022 – BCUC Order G-140-22 addressing FortisBC's objections to interveners' Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
A-17	Letter dated May 31, 2022 – BCUC response to FortisBC's objection to interveners' revised Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
A-18	Letter dated June 20, 2022 – BCUC providing information for Procedural Conference No. 2
A-19	Letter dated July 8, 2022 – BCUC request for submissions regarding expert opinions and further process and scope
A-20	Letter dated August 8, 2022 – BCUC Order G-217-22 with Reasons for Decision amending the regulatory timetable and establishing the format and scope of the oral hearing
A-20-1	Letter dated August 10, 2022 – BCUC issuing Order G-217-22A with Reasons for Decision and amended regulatory timetable and Oral Hearing Scope
A-21	Letter dated August 12, 2022 – BCUC response to FortisBC request for further clarification on Oral Hearing Scope
A-22	Letter dated August 31, 2022 – BCUC Information Request No. 1 to FEI and FBC on FortisBC's Rebuttal Evidence Part 2 – Rebuttal Evidence of Concentric Energy Advisors Inc.
A-23	Letter dated October 13, 2022 – BCUC issuing Oral Hearing Information
A-24	Letter dated November 14, 2022 – BCUC Order G-327-22 with amended regulatory timetable
A-24-1	Letter dated November 14, 2022 – BCUC Order G-327-22A with amended regulatory timetable
A-25	Letter dated November 30, 2022 – BCUC Information Request No. 1 on Undertakings to FortisBC

Exhibit No.	Description
A-26	Letter dated December 9, 2022 – BCUC invitation to registered utilities and interveners to provide additional information in Final Arguments
A-27	Letter dated December 13, 2022 – BCUC request to FortisBC to file credit rating report for FBC
A-28	Letter dated January 26, 2023 – BCUC response to the CEC extension request
A-29	Letter dated January 27, 2023 – BCUC response to BCOAPO extension request
A-30	Letter dated February 17, 2023 – BCUC response to FortisBC extension request
A-31	Letter dated May 8, 2023 – BCUC request for submissions regarding the implementation of rates for utilities that use the FEI Benchmark Utility

COMMISSION STAFF DOCUMENTS

A2-1	Letter dated March 23, 2021 – BCUC Staff submission on scope
A2-2	Letter dated June 18, 2021 – BCUC Staff submit Consultant Report by the Continental Economics, Inc., Dr. Jonathan A. Lesser: Report on Using a Benchmark Utility to Set the Cost of Capital – June 2021
A2-3	Letter dated August 4, 2021 – BCUC Staff submit Consultant Report by the Continental Economics, Inc., Dr. Jonathan A. Lesser: Regulated Utility Cost of Capital: Theory and Canadian Practice – August 2021
A2-3-1	Letter dated November 7, 2022 – BCUC Staff submission: Errata to Consultant Report in Exhibit A2-3
A2-4	Letter dated October 20, 2021 – BCUC Staff submit Consultant Report by the Continental Economics, Inc., Dr. Jonathan A. Lesser: Extension Request dated October 19, 2021
A2-5	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the BCOAPO Information Request No. 1 on Exhibit A2-3

Exhibit No.	Description
A2-6	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the CEC Information Request No. 1 on Exhibit A2-3
A2-7	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to Creative Energy Information Request No. 1 on Exhibit A2-3
A2-8	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to FortisBC Inc. Information Request No. 1 on Exhibit A2-3
A2-9	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the ICG Information Request No. 1 on Exhibit A2-3
A2-10	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to MoveUP Information Request No. 1 on Exhibit A2-3
A2-11	Letter dated November 30, 2021 – BCUC Staff submit Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the RCIA Information Request No. 1 on Exhibit A2-3
A2-12	Letter dated February 28, 2022 – BCUC Staff submit excerpts from Government of Canada Department of Finance Federal Budget 2021, Annex 6: Tax Measures - Supplementary Information, International Tax Measures - Interest Deductibility Limits
A2-13	Letter dated February 28, 2022 – BCUC Staff submitting: A Review of International Approaches to Regulated Rates of Return Prepared for the Australian Energy Regulator by The Brattle Group – June 2020
A2-14	Letter dated February 28, 2022 – BCUC Staff submission: Electric ROE Authorizations Drift Lower In H1'20 As Virus Worries Continue by S&P Global Market Intelligence – August 4, 2020
A2-15	Letter dated February 28, 2022 – BCUC Staff submission: RIIO-ED2 Sector Specific Methodology Decision: Annex 3 Finance by Ofgem– March 11, 2021

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A2-16	Letter dated February 28, 2022 – BCUC Staff submission: Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings by Richard A. Michelfelder and Panayiotis Theodossiou, The Electricity Journal, Volume 26, Issue 9 – November 2013
A2-17	Letter dated April 12, 2022 – BCUC Staff submission: BCUC Staff Draft Regulatory Timetable and Options
A2-18	Letter dated May 16, 2022 – BCUC Staff submission: Betas and Their Regression Tendencies by Marshall E. Blume, The Journal of Finance, Volume 30, Number 3 – June 1975
A2-19	Letter dated May 19, 2022 – BCUC Staff submission: Dr. Lesser Confidentiality Declaration and Undertaking
A2-20	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the BCUC Information Request No. 2 to Dr. Lesser on Coyne Evidence
A2-20-1	Letter dated November 7, 2022 – BCUC Staff submission: Revised Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the BCUC Information Request No. 9.3.1 at the Oral Hearing
A2-21	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the RCIA Information Request No. 2
A2-22	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to ICG Information Request No. 2
A2-23	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the CEC Information Request No. 2
A2-23-1	Letter dated June 21, 2022 – BCUC Staff submission: Consultant amended response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to the CEC Information Request 2 Question 23.1
A2-24	Letter dated June 14, 2022 – BCUC Staff submission: Consultant response by the Continental Economics, Inc., Dr. Jonathan A. Lesser to BCOAPO Information Request No 2
A2-25	Letter dated June 14, 2022 – BCUC Staff submission: Response attachment to BCUC Information Request No. 1.3

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A2-26	Letter dated June 14, 2022 – BCUC Staff submission: Panhandle Eastern Pipe Line Company, LP – Initial Decision – Public Version – March 26, 2021
A2-27	Letter dated June 14, 2022 – BCUC Staff submission: New Regulatory Finance, pp. 190, 303 – 307, 324, by Roger A. Morin, PhD
A2-28	Letter dated June 14, 2022 – BCUC Staff submission: Financial Flexibility, Corporate Investment and Performance: Evidence from Financial Crises – By Ozgur Arslan-Ayaydin, Chris Florackis, Aydin Ozkan
A2-29	Letter dated June 14, 2022 – BCUC Staff submission: On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital – The Journal of Finance – Volume XXXV, No. 2, pp. 369 – 383, May 1980 – By Robert Litzenerger, Krishna Ramaswamy, and Howard Sosin
A2-30	Letter dated June 14, 2022 – BCUC Staff submission: Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings – The Electricity Journal – Volume 29, Issue 9, November 2013 – By Richard A. Michelfelder and Panayiotis Theodossiou
A2-31	Letter dated July 14, 2022 – BCUC Staff submission regarding expert opinions and further process and scope
A2-32	Letter dated October 28, 2022 – BCUC Staff filing Continental Economics, Inc. Dr. Jonathan Lesser CV
A2-33	Letter dated November 7, 2022 – BCUC Staff submission: Witness Aid Part 1 Diverging Opinions of Experts at the Oral Hearing
A2-34	Letter dated November 7, 2022 – BCUC Staff submission: ROE Results Based on Multi-Stage vs Single-Stage DCF to Calculate Forward Looking MRP Experts at the Oral Hearing
A2-35	Letter dated November 7, 2022 – BCUC Staff submission: Return on Equity Calculations Using Different Methodologies and Assumptions (Summary of Exhibit B1-25) at the Oral Hearing
A2-35-1	Letter dated November 9, 2022 – BCUC Staff submission: Amendment to Exhibit A2-35 at the Oral Hearing

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A2-36	Letter dated November 9, 2022 – BCUC Staff submission: Part 2 of the BCUC Witness Aid at the Oral Hearing
A2-37	Letter dated November 9, 2022 – BCUC Staff submission: Section of FortisBC website relating to Sustainability at the Oral Hearing
A2-38	Letter dated November 9, 2022 – BCUC Staff submission: FortisBC Application for Approval of a Multi-Year Rate Plan for 2020 through 2024 at the Oral Hearing
A2-39	Letter dated November 9, 2022 – BCUC Staff submission: FortisBC 2021 Green Bond Impact Report at the Oral Hearing
A2-40	Letter dated November 9, 2022 – BCUC Staff submission: Canadian 2022 Federal Budget page 106 at the Oral Hearing
A2-41	Letter dated November 9, 2022 – BCUC Staff submission: FortisBC Application for Approval of Large Commercial Interruptible Rate page 3 at the Oral Hearing

APPLICANT DOCUMENTS

B1-1	**FORTISBC ENERGY INC. (FEI) –** Letter dated March 16, 2021 submitting registration by Diane Roy
B1-2	Letter dated March 29, 2021 – FEI submission on Preliminary Scope Document
B1-3	Letter dated June 4, 2021 – FEI submission on proceeding Scope and Deferral Account
B1-4	Letter dated July 21, 2021 – FEI submission on Use of a Benchmark Utility
B1-5	Letter dated August 13, 2021 – FEI submission on cost eligibility of PACA
B1-6	Letter dated September 30, 2021 – FEI submitting request for amendment to Regulatory Timetable
B1-7	Letter dated October 15, 2021 – FEI submitting Information Request No. 1 on Exhibit A2-3
B1-8	Letter dated January 31, 2022 – FEI and FBC submitting evidence for Stage 1 of proceeding

Exhibit No.	Description
B1-8-1	Letter dated January 31, 2022 – FEI and FBC submitting evidence for Stage 1 of proceeding – Appendices
B1-8-1-1	Letter dated October 20, 2022 – FortisBC submitting errata to Appendix A – FEI Business Risk Assessment
B1-8-1-2	Letter dated October 20, 2022 – FortisBC submitting September Update to Concentric Financial Models
B1-9	Letter dated April 6, 2022 – FEI and FBC submitting responses to BCUC Information Request No. 1 on FortisBC Evidence
B1-9-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting responses to BCUC Information Request No. 1 on FortisBC Evidence Confidential Attachments
B1-10	Letter dated April 6, 2022 – FEI and FBC submitting responses to BCOAPO Information Request No. 1 on FortisBC Evidence
B1-10-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting responses to BCOAPO Information Request No. 1 on FortisBC Evidence Confidential Attachments
B1-11	Letter dated April 6, 2022 – FEI and FBC submitting responses to CEC Information Request No. 1 on FortisBC Evidence
B1-11-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting confidential response to CEC Information Request No. 1 on FortisBC Evidence and Confidential Attachments
B1-12	Letter dated April 6, 2022 – FEI and FBC submitting responses to ICG Information Request No. 1 on FortisBC Evidence
B1-12-1	**CONFIDENTIAL** - Letter dated April 6, 2022 – FEI and FBC submitting confidential response to ICG Information Request No. 1 Question 5.1 on FortisBC Evidence
B1-13	Letter dated April 6, 2022 – FEI and FBC submitting responses to RCIA Information Request No. 1 on FortisBC Evidence
B1-14	Letter dated May 19, 2022 – FEI and FBC submitting Information Requests Out of Scope

Exhibit No.	Description
B1-15	Letter dated May 26, 2022 – FEI and FBC further submission on Information Requests out of scope
B1-16	Letter dated May 30, 2022 – FEI and FBC submitting response to ICG Information Request No. 2 regarding Dr. Lesser
B1-17	Letter dated June 14, 2022 – FortisBC submitting response to RCIA Information Request No. 2 on FortisBC Evidence
B1-18	Letter dated June 14, 2022 – FortisBC submitting response to CEC Information Request No. 2 on FortisBC Evidence
B1-19	Letter dated June 14, 2022 – FortisBC submitting response to BCOAPO Information Request No. 2 on FortisBC Evidence
B1-19-1	**CONFIDENTIAL** - Letter dated June 14, 2022 – FortisBC submitting confidential responses to BCOAPO Information Request No. 2 on FortisBC Evidence
B1-20	Letter dated June 14, 2022 – FortisBC submitting response to BCUC Information Request No. 2 on FortisBC Evidence
B1-21	Letter dated June 28, 2022 – FortisBC submitting Rebuttal Evidence
B1-22	Letter dated July 14, 2022 – FortisBC submission regarding expert opinions and further process and scope
B1-23	Letter dated July 20, 2022 – FortisBC reply submission regarding expert opinions and further process and scope
B1-24	Letter dated August 11, 2022 – FortisBC request further clarification on Oral Hearing Scope
B1-25	Letter dated October 20, 2022 – FortisBC submitting responses to BCUC Information Request No. 1 on Rebuttal Evidence
B1-25-1	Letter dated November 4, 2022 – FortisBC submitting errata to responses to BCUC Information Request No. 1 Question 6.2 on Rebuttal Evidence
B1-26	Letter dated October 20, 2022 – FortisBC submitting responses to BCOAPO Information Request No. 1 on Rebuttal Evidence

Exhibit No.	Description
B1-27	Letter dated October 20, 2022 – FortisBC submitting responses to CEC Information Request No. 1 on Rebuttal Evidence
B1-28	Letter dated October 20, 2022 – FortisBC submitting responses to RCIA Information Request No. 1 on Rebuttal Evidence
B1-29	Letter dated October 31, 2022 – FortisBC submitting Witness Panel, Direct Testimony and Notice of Cross-Examination
B1-30	Letter dated November 3, 2022 – FortisBC submitting Opening Statements
B1-31	Letter dated November 7, 2022 – FortisBC submitting Concentric Energy Advisor Multi-Stage DCF and CAPM Results at the Oral Hearing
B1-32	Letter dated November 7, 2022 – FortisBC submitting U.S. Court of Appeals Emera Maine No. 15-1118 at the Oral Hearing
B1-33	Letter dated November 7, 2022 – FortisBC submitting U.S. Court of Appeals MISO ROE Opinion No. 16-1325 at the Oral Hearing
B1-34	Letter dated November 7, 2022 – FortisBC submitting PPL Corporation sell of U.K. Utility Business at the Oral Hearing
B1-35	Letter dated November 7, 2022 – FortisBC submitting PNM Resources Investor News Releases at the Oral Hearing
B1-36	Letter dated November 8, 2022 – FortisBC submitting US Securities and Exchange Commission Quarterly Report at the Oral Hearing
B1-37	Letter dated November 8, 2022 – FortisBC submitting Consolidated Edison Quarterly Earnings Presentation at the Oral Hearing
B1-38	Letter dated November 8, 2022 – FortisBC submitting Exelon Fall 2022 Investor Meetings at the Oral Hearing
B1-39	Letter dated November 8, 2022 – FortisBC submitting US Federal Energy Regulatory Commission Hearing at the Oral Hearing
B1-40	Letter dated November 8, 2022 – FortisBC submitting Testimony of Dr Lesser before the Arkansas Public Service Commission at the Oral Hearing

Exhibit No.	Description
B1-41	Letter dated November 8, 2022 – FortisBC submitting Testimony of Dr Lesser before the Illinois Commerce Commission at the Oral Hearing
B1-42	Letter dated November 8, 2022 – FortisBC submitting Bank of Canada Interest Rates at the Oral Hearing
B1-43	Letter dated November 8, 2022 – FortisBC submitting S&P TSX Utilities Index Dividend Yield at the Oral Hearing
B1-44	Letter dated November 8, 2022 – FortisBC submitting excerpt Capital Pricing Model from Exhibit B1-8-1-1 at the Oral Hearing
B1-45	Letter dated November 8, 2022 – FortisBC submitting 169 FERC Docket Nos. EL14-12-003 and EL15-45-000 at the Oral Hearing
B1-46	Letter dated November 8, 2022 – FortisBC submitting Wilshire 5000 Total Market Full Cap Index/Gross Domestic Product at the Oral Hearing
B1-47	Letter dated November 8, 2022 – FortisBC submitting Stock Market Capitalization to GDP for Canada at the Oral Hearing
B1-48	Letter dated November 8, 2022 – FortisBC submitting charts showing 10-year Actual vs Consensus Forecasts in Canada and the US at the Oral Hearing
B1-49	Letter dated November 9, 2022 – FortisBC submitting FEI 2022 Long Term Gas Resource Plan excerpt at the Oral Hearing
B1-50	Letter dated November 23, 2022 – FortisBC submitting response to Undertakings
B1-50-1	Letter dated December 12, 2022 – FortisBC providing Moody Credit Rating Report regarding response to Undertaking No. 3
B1-51	Letter dated December 9, 2022 – FortisBC submitting response to BCUC Information Request No. 1 Undertakings
B1-52	Letter dated December 9, 2022 – FortisBC submitting response to CEC Information Request No. 1 Undertakings
B1-53	Letter dated December 9, 2022 – FortisBC submitting response to RCIA Information Request No. 1 Undertakings

Exhibit No.	Description
B1-54	Letter dated February 17, 2023 – FortisBC submitting extension request to file Reply Argument
B2-1	**FORTISBC INC. (FBC) –** Letter dated March 16, 2021 submitting registration by Diane Roy
B2-2	Letter dated March 29, 2021 – FBC submission on Preliminary Scope Document
B2-3	Letter dated June 4, 2021 – FBC submission on proceeding Scope and Deferral Account
B2-4	Letter dated July 21, 2021 – FBC submission on Use of a Benchmark Utility
B2-5	Letter dated August 13, 2021 – FBC submission on cost eligibility of PACA
B2-6	Letter dated September 30, 2021 – FBC submitting request for amendment to Regulatory Timetable
B2-7	Letter dated October 15, 2021 – FBC submitting Information Request No. 1 on Exhibit A2-3
B2-8	Letter dated December 14, 2022 – FBC submitting Moody Credit Rating Report regarding response to Undertaking
B3-1	**FORTISBC ALTERNATIVE ENERGY SERVICE INC. (FAES) –** Letter dated March 16, 2021 submitting registration by Grant Bierlmeier
B3-2	Letter dated March 31, 2021 – FAES submission on Preliminary Scope Document
B3-3	Letter dated June 4, 2021 – FAES submission on proceeding Scope and Deferral Account
B3-4	Letter dated July 21, 2021 – FAES submission on Use of a Benchmark Utility
B4-1	**Nelson Hydro** – Letter dated March 19, 2021 submitting registration by Gabriel Bouvet-Boisclair
B4-2	Letter dated March 30, 2021 – Nelson Hydro submission on Preliminary Scope Document
B4-3	Letter dated July 21, 2021 – Nelson Hydro submission on Use of a Benchmark Utility
B4-4	Letter dated August 13, 2021 – Nelson Hydro submission on cost eligibility of PACA

Exhibit No.	Description
B5-1	**Kyuquot Power Ltd. (KPL)** – Letter dated March 22, 2021 submitting registration by Taya DeAngelis
B5-2	Letter dated March 31, 2021 – KPL submission on Preliminary Scope Document
B6-1	**Corx Multi-Utility Services Inc. (Corix)** – Letter dated March 22, 2021 submitting registration by Errol South
B6-2	Letter dated March 31, 2021 – Corix submission on Preliminary Scope Document
B6-3	Letter dated June 4, 2021 – Corix submission on proceeding Scope and Deferral Account
B6-4	Letter dated July 21, 2021 – Corix Brattle Report submission on Use of a Benchmark Utility
B6-5	Letter dated July 21, 2021 – Corix submission on Use of a Benchmark Utility
B6-6	Letter dated August 12, 2021 – Corix submission on cost eligibility of PACA
B7-1	**Creative Energy Vancouver platforms Inc. (Creative Energy)** – Letter dated March 22, 2021 submitting registration by Rob Gorter
B7-2	Letter dated March 31, 2021 – Creative Energy submission on Preliminary Scope Document
B7-3	Letter dated June 4, 2021 – Creative Energy submission on proceeding Scope and Deferral Account
B7-4	Letter dated July 21, 2021 – Creative Energy submission on Use of a Benchmark Utility
B7-5	Letter dated August 13, 2021 – Creative Energy submission on cost eligibility of PACA
B7-6	Letter dated October 15, 2021 – Creative Energy submitting Information Request No. 1 on Exhibit A2-3
B8-1	**River District Energy (RDE)** – Letter dated March 18, 2021 submitting registration by Ross Hanson
B8-2	Letter dated March 31, 2021 – RDE submission on Preliminary Scope Document

Exhibit No.	Description
B9-1	**Pacific Northern Gas Ltd. (PNG) and Pacific Northern Gas (N.E.) Ltd. (PNGNE) (collectively PNG)** – Letter dated March 24, 2021 submitting registration by Gordon Doyle
B9-2	Letter dated March 31, 2021 – PNG submission on Preliminary Scope Document
B9-3	Letter dated June 4, 2021 – PNG submission on proceeding Scope and Deferral Account
B9-4	Letter dated July 21, 2021 – PNG submitting notice of Additional Contact
B9-5	Letter dated July 21, 2021 – PNG Brattle Report submission on Use of a Benchmark Utility
B9-6	Letter dated July 21, 2021 – PNG submission on Use of a Benchmark Utility
B9-7	Letter dated August 13, 2021 – PNG submission on cost eligibility of PACA

INTERVENER DOCUMENTS

C1-1	**RESIDENTIAL CONSUMER INTERVENER ASSOCIATION (RCIA) –** Letter dated March 12, 2021 submitting request to intervene by Fredrik Ambrosson
C1-2	Letter dated March 31, 2021 – RCIA submission on Preliminary Scope Document
C1-3	Letter dated June 4, 2021 – RCIA submission on proceeding Scope and Deferral Account
C1-4	Letter dated July 21, 2021 – RCIA submission on Use of a Benchmark Utility
C1-5	Letter dated August 13, 2021 – RCIA submission on cost eligibility of PACA
C1-6	Letter dated October 12, 2021 – RCIA submitting Information Request No. 1 on Exhibit A2-3
C1-7	Letter dated March 7, 2022 – RCIA submitting Information Request No. 1 on FortisBC Evidence
C1-8	Letter dated May 16, 2022 – RCIA submitting Information Requests No. 2 to FortisBC and Dr. Lesser regarding Mr. Coyne's evidence

Exhibit No.	Description
C1-8-1	Letter dated May 25, 2022 – RCIA submitting revised Information Requests No. 2 to FortisBC and Dr. Lesser regarding Mr. Coyne's evidence
C1-9	Letter dated July 14, 2022 – RCIA submission regarding expert opinions and further process and scope
C1-10	Letter dated September 12, 2022 – RCIA submitting Information Request No. 1 to FortisBC on Rebuttal Evidence Part 2-Concentric Rebuttal Evidence
C1-11	Letter dated November 8, 2022 – RCIA submitting Witness Aid Part 1 at the Oral Hearing
C1-12	Letter dated November 8, 2022 – RCIA submitting Witness Aid Part 2 at the Oral Hearing
C1-13	Letter dated November 29, 2022 – RCIA submitting Information Request No. 1 on FortisBC response to Undertakings
C2-1	**Movement of United Professionals (MoveUP)** – Letter dated March 14, 2021 submitting request to intervene by Jim Quail
C2-2	Letter dated March 31, 2021 – MoveUP submission on Preliminary Scope Document
C2-3	Letter dated July 16, 2021 – MoveUP submission on Order G-183-21 Appendix A
C2-4	Letter dated August 13, 2021 – MoveUP submission on cost eligibility of PACA
C2-5	Letter dated October 12, 2021 – MoveUP submitting Information Request No. 1 on Exhibit A2-3
C3-1	**Boralex Ocean Falls Limited Partnership (Boralex LP) –** Letter dated March 22, 2021 submitting request to intervene by Maxime Tremblay
C4-1	**Association of Major Power Customers of BC (AMPC) –** Letter dated March 22, 2021 submitting request to intervene by Matthew Keen
C4-2	Letter dated April 1, 2021 – AMPC submission on Preliminary Scope Document
C5-1	**Industrial Customers Group (ICG)** – Letter dated March 22, 2021 submitting request to intervene by Robert Hobbs
C5-2	Letter dated March 31, 2021 – ICG submission on Preliminary Scope Document
C5-3	Letter dated June 4, 2021 – ICG submission on proceeding Scope and Deferral Account

Exhibit No.	Description
C5-4	Letter dated July 21, 2021 – ICG submission on Use of a Benchmark Utility
C5-5	Letter dated August 13, 2021 – ICG submission on cost eligibility of PACA
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C5-7	Letter dated March 7, 2022 – ICG submitting Information Request No. 1 on FortisBC Evidence
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C5-8-1	Letter dated May 25, 2022 – ICG submitting revised Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C5-9	Letter dated May 27, 2022 – ICG submission regarding revised Information Request No. 2
C5-10	Letter dated July 14, 2022 – ICG submission regarding expert opinions and further process and scope
C5-11	Letter dated November 7, 2022 – ICG submitting Confidential Declaration and Undertaking
C6-1	**Commercial Energy Consumers Association of British Columbia (CEC)** – Letter dated March 22, 2021 submitting request to intervene by Christopher Weafer
C6-2	Letter dated March 31, 2021 – CEC submission on Preliminary Scope Document
C6-3	Letter dated June 4, 2021 – CEC submission on proceeding Scope and Deferral Account
C6-4	Letter dated July 21, 2021 – CEC submission on Use of a Benchmark Utility
C6-5	Letter dated August 13, 2021 – CEC submission on cost eligibility of PACA
C6-6	Letter dated October 8, 2021, CEC submitting extension request to file Information Requests on Exhibit A2-3
C6-7	Letter dated October 15, 2021 – CEC submitting Information Request No. 1 on Exhibit A2-3
C6-8	Letter dated March 7, 2022 – CEC submitting Information Request No. 1 on FortisBC Evidence

Exhibit No.	Description
C6-9	Letter dated May 16, 2022 – CEC submitting Information Request No. 2 on FortisBC Evidence
C6-10	Letter dated May 16, 2022 – CEC submitting Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C6-11	Letter dated July 14, 2022 – CEC submission regarding expert opinions and further process and scope
C6-12	Letter dated September 12, 2022 – CEC submitting Information Request No. 1 to FortisBC on Rebuttal Evidence Part 2-Concentric Rebuttal Evidence
C6-13	Letter dated November 8, 2022 – CEC submitting Fortis Inc. Releases Second Quarter 2022 Results and 2022 Sustainability Report at the Oral Hearing
C6-14	Letter dated November 9, 2022 – CEC submitting Fortis Inc. Investor Presentation Q4 2022 at the Oral Hearing
C6-15	Letter dated November 9, 2022 – CEC submitting Witness Aid for Excerpts from Long Term Gas Resource Plan at the Oral Hearing
C6-16	Letter dated November 30, 2022 – CEC submitting Information Request No. 1 on Undertakings
C6-17	Letter dated January 24, 2023 – CEC submitting extension request to file Final Argument
C7-1	**British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, Tenants Resource and Advisory Centre, and Together Against Poverty Society (BCOAPO et al.) –** Letter dated March 22, 2021 submitting request to intervene by Leigha Worth and Irina Mis
C7-2	Letter dated March 31, 2021 – BCOAPO submission on Preliminary Scope Document
C7-3	Letter dated July 21, 2021 – BCOAPO submission on Use of a Benchmark Utility
C7-4	Letter dated August 13, 2021 – BCOAPO submission on cost eligibility of PACA
C7-5	Letter dated October 15, 2021 – BCOAPO submitting Information Request No. 1 on Exhibit A2-3
C7-6	Letter dated March 7, 2022 – BCOAPO submitting Information Request No. 1 on FortisBC Evidence

Exhibit No.	Description
C7-7	Letter dated May 16, 2022 – BCOAPO submitting Information Request No. 2 to FortisBC
C7-8	Letter dated May 16, 2022 – BCOAPO submitting Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
C7-9	Letter dated July 14, 2022 – BCOAPO submission regarding expert opinions and further process and scope
C7-10	Letter dated September 12, 2022 – BCOAPO submitting Information Request No. 1 to FortisBC on Rebuttal Evidence Part 2-Concentric Rebuttal Evidence
C7-11	Letter dated January 26, 2022 – BCOAPO submitting extension request to file Final Argument
C8-1	**BRITISH COLUMBIA HYDRO AND POWER AUTHORITY (BC HYDRO) –** Letter dated March 22, 2021 submitting request to intervene by Fred James
C8-2	Letter dated June 4, 2021 – BC Hydro submission on proceeding Scope and Deferral Account
C9-1	**CLEAN ENERGY ASSOCIATION OF BC (CEABC) –** Letter dated March 22, 2021 submitting request to intervene by Laureen Whyte
C9-2	Letter dated June 1, 2021 – CEABC submission on proceeding Scope and Deferral Account
C9-3	Letter dated April 12, 2021 – CEABC withdrawing intervener status

INTERESTED PARTY DOCUMENTS

D-1	**ONNI GROUP (ONNI)** - Submission dated March 23, 2021 request for Interested Party Status by Michelle McLarty
D-2	**CHOY, MAURICE (CHOY)** - Submission dated July 13, 2021 request for Interested Party Status
D-3	**JARVI, MARK (JARVI)** – Submission dated July 28, 2021 request for Interested Party Status

LETTERS OF COMMENT

E-1	**DE LA GARZA, S. (DELAGARZA)** – Letter of Comment dated February 15, 2022

AUC
Alberta Utilities Commission

Determination of the Cost-of-Capital Parameters in 2024 and Beyond

October 9, 2023

Alberta Utilities Commission
Decision 27084-D02-2023
Determination of the Cost-of-Capital Parameters in 2024 and Beyond
Proceeding 27084

October 9, 2023

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The Commission may, no later than 60 days from the date of this decision and without notice, correct typographical, spelling and calculation errors and other similar types of errors and post the corrected decision on its website.

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Calgary, Alberta

Determination of the Cost-of-Capital Parameters in 2024 and Beyond — **Decision 27084-D02-2023**, **Proceeding 27084**

1 Decision summary

1. In this generic cost of capital (GCOC) decision, the Alberta Utilities Commission adopts a formulaic approach, utilizing the equity risk premium (ERP) methodology, to calculate the fair rate of return on equity (ROE) for Alberta's electric and gas utilities in 2024 and beyond. The Commission has determined that the ROE resulting from the formulaic approach will uniformly apply to all of the utilities.

2. This decision also outlines the approved deemed equity ratios (sometimes referred to by parties as "equity thickness"; collectively, the ROE and equity ratios, are referred to as "cost-of-capital parameters") for the utilities on a final basis. Specifically, accounting for differences in the risk of each of the utilities, the Commission has determined that no change is required to the deemed equity ratios approved in the 2018 GCOC decision.[1]

3. The Commission institutes a mandatory review of cost-of-capital parameters every five years, subject to mid-term reopeners either at its own discretion or upon application from interested parties. The established cost-of-capital parameters will apply to the following utilities:

- AltaLink Management Ltd.
- Apex Utilities Inc.
- ATCO Electric Ltd.
- ATCO Gas and Pipelines Ltd.
- ENMAX Power Corporation
- EPCOR Distribution & Transmission Inc.
- FortisAlberta Inc.
- KainaiLink L.P.
- City of Lethbridge
- PiikaniLink L.P.
- The City of Red Deer
- TransAlta Corporation

4. The Commission's decision to implement the formulaic approach for ROE determination is driven by a commitment to reduce regulatory lag and regulatory burden, enhance transparency, and deliver regulatory certainty, while balancing the interests of all stakeholders. This approach is a significant step for GCOC proceedings towards a more efficient, predictable and cost-effective regulatory process that ultimately benefits ratepayers, utilities and the broader public interest in Alberta.

[1] Decision 22570-D01-2018: 2018 Generic Cost of Capital, Proceeding 22570, August 2, 2018.

5. The Commission approves the following formulaic approach to determine the ROE in 2024 and subsequent years:

$$ROE_t = 9.0\% + 0.5 \times (\mathrm{YLD}_t - 3.10\%) + 0.5 \times (\mathrm{SPRD}_t - \mathrm{SPRD}_{base})$$[2]

6. That is, in each year, the approved ROE will be determined by adjusting the notional ROE of 9.0 per cent approved in this decision by the difference in forecast long-term Government of Canada (GoC) bond yield (YLD_t) and utility bond yield spread ($SPRD_t$) from their base values of 3.10 per cent and the bond yield spread for the month of February 2023, respectively. These forecasts will be calculated by the Commission in early November of each year as follows:

(i) The forecast long-term GoC bond yield will be calculated as the weighted average of (a) the 30-year GoC bond yield forecasts published by Royal Bank of Canada (RBC), TD Bank (TD) and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (b) the naïve forecast[3] representing the average long-term GoC bond yield[4] over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.

(ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield[5] and the long-term GoC bond yield[6] over the period October 1 to October 31 of each year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

7. The cost-of-capital parameters for the various investor-owned water utilities under the Commission's jurisdiction were not determined in this proceeding. However, the determinations in this proceeding may be considered in other proceedings should issues respecting ROE and deemed equity ratios arise for these utilities.

2 Background and procedural summary

8. On January 3, 2022, the Commission established a bifurcated process for this proceeding with the goal of determining ROE and deemed equity ratios. The first part of the proceeding (Stage 1) established the cost-of-capital parameters for 2023 and was completed on March 31, 2022, with the release of Decision 27084-D01-2022.[7] This decision addresses the second part of the proceeding (Stage 2), establishes a formulaic approach for setting ROE in 2024 and each year

2 The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.
3 A "naïve forecast" is a forecasting method that uses actual values from a previous period.
4 Bank of Canada CANSIM Series V39056.
5 Bloomberg Series C29530Y.
6 Bank of Canada CANSIM Series V39056.
7 Decision 27084-D01-2022: 2023 Generic Cost of Capital, Proceeding 27084, March 31, 2022.

thereafter, and sets the deemed equity ratios for the utilities. More specifically, the scope of Stage 2 comprised the following key objectives:

- Explore potential formula-based approaches for determining the ROE and identify a preferred formulaic method. This approach was intended to enhance transparency and predictability, ultimately saving both customers and Alberta utilities significant time, resources and costs associated with conducting fully litigated proceedings every one to three years.
- Establish the initial numerical variables required for the formula. This included defining an initial base, or notional ROE, that would form an integral part of the formula and serve as the basis for determining the ROE for the 2024 and future test years.
- Delineate the process for calculating the ROE in future test years while ensuring clarity and consistency in the methodology.
- Identify future processes or thresholds that would trigger a review of the formulaic approach and any necessary adjustments by the Commission, should such adjustments be deemed necessary.
- Evaluate whether the Commission should revise deemed equity ratios while employing a formulaic approach to determining the ROE.

9. By pursuing these objectives, the Commission aimed to provide a more structured and efficient framework for determining ROE and related parameters for 2024 and beyond.

10. Each of the utilities, except Lethbridge, Red Deer, TransAlta, KainaiLink L.P. and PiikaniLink L.P., actively participated in this proceeding. ATCO Electric and ATCO Gas (ATCO Utilities), Apex and Fortis co-sponsored the evidence of Dr. Bente Villadsen and Frank Graves. Apex also sponsored the stand-alone evidence of Michael Tolleth. AltaLink and EPCOR co-sponsored the evidence of Dylan D'Ascendis. ENMAX sponsored the evidence of Concentric Energy Advisors, Inc. (James Coyne and John Trogonoski) and Nicole Martin. Additionally, each of Apex, Fortis and the ATCO Utilities filed company-specific evidence.

11. The Consumers' Coalition of Alberta (CCA), the Office of the Utilities Consumer Advocate (UCA), and the Industrial Power Consumers Association of Alberta (IPCAA) (collectively, the interveners or customer groups) also actively participated in the proceeding. The CCA sponsored the evidence of Jan Thygesen; the UCA sponsored the evidence of Dr. Sean Cleary and Russ Bell; and IPCAA sponsored the evidence of Dustin Madsen.

12. To assist with the development of a comprehensive record and to prevent prolonged and unproductive debates among the parties regarding the suitability of various utility comparator groups used to construct models for estimating the fair ROE for Alberta utilities, the Commission took a proactive approach. At the outset of Stage 2 of the proceeding, on October 14, 2022, the Commission organized a technical conference for parties (involving participants from utilities and customer groups) with the primary purpose to discuss and formulate a comparator group of representative utilities that would inform the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE.

13. The outcome of the discussions during the technical conference was documented in appendixes A and B of the Commission's letter, dated October 24, 2022,[8] which captured the consensus among parties regarding the Commission's proposed screening criteria for determining a comparator group. The appendixes also highlighted other areas where consensus was achieved or, in some instances, where consensus was not achieved. While agreement was reached on the majority of topics discussed at the technical conference, some matters still required further input from all parties. These additional submissions were subsequently received by the Commission on November 2, 2022.

14. On November 10, 2022, the Commission issued its determinations on the unresolved matters and, using the approved screening criteria, produced the list of comparator utilities. The Commission also circulated to parties a preliminary list of issues to be considered in this proceeding and provided parties the opportunity to highlight any material issues they believed the Commission should consider in Stage 2 of this proceeding that had not been identified in the list. Based on parties' feedback, a finalized issues list for Stage 2 of this proceeding was released on November 29, 2022, which parties used as a foundation for their evidentiary submissions.

15. In addition to having parties file evidence, the Commission's processes included information requests (IRs) and responses to evidence filed and/or sponsored by the utilities; IRs and responses to evidence sponsored by the interveners; concurrent rebuttal evidence filed by the utilities and interveners; and a one-week virtual oral hearing. The Commission also established a process for simultaneous written argument and reply argument. The Commission considers that the record of this proceeding closed with the filing of reply arguments on July 11, 2023.

16. The Commission reviewed the entire record in coming to this decision; lack of reference to a matter addressed in the evidence and submissions does not mean that the Commission did not consider it.

3 Fair return standard

17. The legislation that governs the Commission requires that it fix just and reasonable rates for the utilities it regulates.[9] The Commission is guided in this task by well-developed case law on the meaning of just and reasonable rates, which includes determining a fair return on the equity component of invested capital, or the fair return standard. These concepts are set out in three seminal decisions: the Supreme Court of Canada's decision in *Northwestern Utilities v Edmonton (City),*[10] and two cases from the Supreme Court of the United States, *Bluefield*

8 Exhibit 27084-X0239.01.

9 See Section 89 of the *Public Utilities Act;* Section 36(a) of the *Gas Utilities Act;* and Section 121(2)(a) of the *Electric Utilities Act.* Note that the *Electric Utilities Act* also requires the Commission to provide an owner of an electric utility with a reasonable opportunity to recover a fair return on the equity of shareholders of the electric utility as it relates to the investment (Section 122(1)(a)(iv)). The *Gas Utilities Act* and the *Public Utilities Act* requires the Commission to fix a fair return on the rate base (Section 37(1)). The Commission considers these statutory requirements to be the same.

10 *Northwestern Utilities v Edmonton (City)* [1929] SCR 186 (*Northwestern Utilities*).

Waterworks and Improvement Company v Public Service Commission of the State of West Virginia,[11] and *Federal Power Commission v Hope Natural Gas Company.*[12]

18. In *Northwestern Utilities*, the Supreme Court of Canada addressed whether a board had correctly set the rate for a utility. In enunciating the meaning of "fair return," the court wrote:

> 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.[13]

19. A similar statement was made by the Supreme Court of the United States in *Bluefield*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties …[14]

20. In *Hope*, the Supreme Court of the United States also spoke to comparable investments, as well as the importance of financial integrity and capital attraction:

> The ratemaking process under the Act, *i.e.,* the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the *Natural Gas Pipeline Co.* case that "regulation does not insure that the business shall produce net revenues."… But, such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock…. By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[15] [footnotes omitted]

21. The requirements of comparable investments, financial integrity, and capital attraction remain fundamental to setting a fair return. The Commission and its predecessors have employed

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[11] *Bluefield Waterworks and Improvement Company v Public Service Commission of the State of West Virginia*, 262 US 679 (1923) (*Bluefield*).
[12] *Federal Power Commission v Hope Natural Gas Company*, 320 US 591 (1944) (*Hope*).
[13] *Northwestern Utilities*, page 193.
[14] *Bluefield*, page 692.
[15] *Hope*, page 603.

these principles in setting rates of return,[16] and other regulators also apply these principles.[17] All three components must be satisfied to arrive at a fair return.

22. While satisfying these principles is fundamental to arriving at a fair return, the foundational cases also highlight the importance of ensuring that the interests of utilities are considered with those of consumers, in order to ensure that rates are just and reasonable. In *Northwestern Utilities,* the court wrote that the board had a duty to "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."[18] Similarly, in *Hope,* the court stated that "… the fixing of 'just and reasonable rates' involves a balancing of the investor and consumer interests."[19]

23. The National Energy Board outlined the balancing exercise as follows:

> To put the matter another way, when the cost of service methodology is used to determine just and reasonable tolls, if the Board does not permit the Mainline [natural gas transmission system] to recover its costs because it has understated the Mainline's cost of equity capital, the Mainline will be unable to earn a fair return on equity. The tolls will therefore not be just and reasonable from the Mainline's point of view. On the other hand, the tolls must also be just and reasonable from the point of view of the Mainline's customers and the ultimate consumers who rely on service from the Mainline. Therefore, customers and consumers have an interest in ensuring that the Mainline's costs are not overstated.[20]

24. The Commission must therefore set a rate of return, and ensure that the fair return requirements of comparable investments, financial integrity, and capital attraction are satisfied, while also being mindful of the need to ensure that rates are just and reasonable for both the utilities and consumers. As noted by the Commission in the 2018 GCOC decision:

> The Commission exercises its judgment in determining a total return for each utility to establish rates that provide the utility a reasonable opportunity to earn a fair return on invested capital while ensuring that rates are just and reasonable so that customers are not paying more than is required to maintain safe, reliable and economic service.[21]

25. The Commission must therefore review all evidence before it, in order to ensure that it achieves the three fundamental requirements in setting a fair return, while at the same time ensuring that the decision it arrives at results in rates that are just and reasonable for both utilities and consumers.

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16 Decision 2004-052: Generic Cost of Capital, AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd., Application 1271597, July 2, 2004, page 13. See also Decision 2009-216: 2009 Generic Cost of Capital, Proceeding 85, Application 1578571, November 12, 2009, which provided an extensive discussion of the fair return standard at paragraphs 82-109.

17 See National Energy Board Decision RH-2-2004, Reasons for Decision, TransCanada Pipelines Limited, Phase II, Released: April 2005.

18 *Northwestern Utilities,* pages 192-193.

19 *Hope,* page 603.

20 *TransCanada Pipelines Limited v Canada (National Energy Board)*, 2004 FCA 149 (*TransCanada Pipelines*), paragraph 34.

21 Decision 22570-D01-2018, paragraph 37.

26. The Commission has significant discretion in addressing this complex task. In *Bluefield,* the court wrote that "(w)hat annual rate will constitute just compensation depends on many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts."[22] In a concurring judgment in the *Northwestern Utilities* case, Justice Smith noted that "[t]he question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board."

27. There were 949 exhibits filed in this proceeding, and thousands of pages of evidence and submissions. There were significant matters of dispute between the parties and expert opinion that differed on critical points. The Commission must consider and weigh this evidence, and applying its judgment, make decisions that meet the fair return standard, and result in just and reasonable rates. As noted by Justice Rothstein of the Federal Court of Appeal:

> … In cost of capital proceedings, the Board is entitled, on the basis of the evidence before it and the use of its own judgment, to choose a methodology for determining cost of capital and to estimate the cost of capital for a forthcoming year. Very often, the Board's estimate will not reflect the precise estimates of one side or the other or of one witness or another. Having regard to all the evidence, the Board will determine its own estimate.[23]

4 Relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision

28. In this section, the Commission considers changes in economic and market conditions, both global and domestic, since the 2018 GCOC decision. Macroeconomic conditions, such as economic growth and interest rates, factor into the Commission's determination of an approved fair cost of capital because they are inputs in the models used to develop those costs.

29. In this proceeding, there was a general consensus among witnesses that the COVID-19 pandemic, and the varied responses to it in different countries, produced uncertain and volatile macroeconomic and capital market conditions not just in Canada or North America, but worldwide. This instability was compounded by government and central bank policies that, first, attempted to stabilize economic activity and then reacted to a quick economic rebound as the pandemic subsided. The U.S. and Canadian central banks lowered policy interest rates at the onset of the pandemic to promote economic activity while also purchasing bonds to stabilize debt markets (this asset-purchasing transaction is commonly referred to as quantitative easing). When the pandemic subsided in 2022, central banks increased interest rates in response to higher inflation and reduced their bond holdings (quantitative tightening). The Commission observes that economies and capital markets are still managing the residual fallout of the pandemic.

30. In the 2018 GCOC decision, the Commission concluded that global and Canadian economic conditions had improved since the 2016 GCOC proceeding.[24] The Commission made note of global and national economic growth, reduced market volatility, a modest increase in the 30-year GoC bond yield, and a compression in credit spreads. However, having regard to

22 *Bluefield*, page 692.
23 *TransCanada Pipelines*, paragraph 58.
24 Decision 22570-D01-2018, paragraph 192.

downward pressure from other factors, the Commission found that the approved ROE for 2018 should be set at or near that of the 2016 proceeding.[25]

31. The evidence in this proceeding is that macroeconomic and capital market conditions are somewhat less favourable now than they were at the time the 2018 GCOC decision was issued. However, the Commission views the current conditions as transitionary and likely to improve as inflation abates and the economy adjusts to higher interest rates than the abnormally low rates that prevailed in the relatively recent past.

32. The Commission agrees that higher inflation and higher interest rates since 2018 have created uncertainty in the broader economy, which is reflected in market volatility and in the Bank of Canada's (BoC) expectation for lower growth in 2023 and 2024. The credit spread between A-rated utilities and government bonds has also increased somewhat, demonstrating investors' concerns about the macroeconomic conditions for utilities. Capital market volatility, although having moderated recently, could flare up again until investors are once again confident that conditions have stabilized.

33. The Commission acknowledges the risk of a recession, but defers to the BoC's guidance as submitted by Dr. Cleary and Dr. Villadsen that economic growth will continue albeit at a slower pace. The Commission also notes that Alberta is resource dependent and agrees with Dr. Cleary's assessment that the anticipated economic slowdown in the rest of Canada will be less pronounced in Alberta as a result.

34. The Commission expects a normalization in macroeconomic conditions, including a sustained, if uneven, amelioration in the pace of inflation. As well, the Commission expects an eventual halt, then partial reversal, in the BoC's policy interest rate hikes at, or not much beyond, the level at which rates presently stand. Lower gross domestic product (GDP) growth is expected to reduce demand in the economy and, consequently, inflationary pressures as well. The Commission expects that the BoC will achieve its inflationary target; however, timelines for meeting that target remain unclear. As macroeconomic conditions stabilize, capital market conditions are expected to respond in kind with lower volatility and stabilizing bond yields. The Commission expects a higher interest rate environment for longer, which would be reflected in higher utility bond yields relative to 2018. However, the Commission agrees with J. Thygesen's contention that a slower growth environment or a recession may require the BoC or the Federal Reserve in the U.S. to reduce interest rates, which would put downward pressure on future utility bond yields, all else being equal.

35. Even accepting that there has been a deterioration in macroeconomic conditions since 2018, the Commission finds that many economic indicators (among them prolonged disruptions in global supply chains; pronounced volatility in prices for energy, grain and other foodstuffs; widespread workforce dislocations; health concerns; and pressures on medical systems, etc.) have begun stabilizing to a greater or lesser extent since the height of the pandemic and Russia's invasion of Ukraine. In addition, of the remaining post-pandemic economic shocks, including higher interest rates and inflation in excess of the BoC's target range, the Commission finds that

[25] Decision 22570-D01-2018, paragraph 206.

Alberta's regulatory framework has, to a significant extent, shielded Alberta utilities from much of the impact of these systematic risks.[26]

36. The fact that a supportive regulatory environment can provide significant protection to utilities from rising costs occasioned by adverse macroeconomic changes is demonstrated by robust returns achieved by Alberta utilities during the pandemic years 2020 to 2022.[27] While many competitive industries were particularly hard hit by pandemic-related dislocations, Alberta regulated utilities appear to have avoided any significant harm and, indeed, experienced positive financial results throughout.

37. All parties provided evidence on relevant changes in macroeconomic and capital market conditions since the 2018 GCOC decision. Sections 4.1 to 4.4 that follow briefly summarize parties' submissions focusing on inflation, economic growth, bond yields and capital markets upon which the Commission has based its analysis and conclusions.

4.1 Inflation

38. Three utility witnesses (D. D'Ascendis, Dr. Villadsen and J. Coyne) identified high inflation as a primary risk to the economy in general, and to utility capital costs in particular. In their argument, ATCO-Fortis-Apex noted that inflation peaked in June 2022, at 8.1 per cent in Canada and remains above the BoC target range of one to three per cent.[28] The BoC, in response to higher inflation, increased its policy interest rate more than nine times since March 2022[29] and began quantitative tightening.[30] J. Coyne noted that while inflation has abated from its peak in 2022, inflationary pressures remain in the economy, which contributes to market instability.[31] D. D'Ascendis concluded that increased inflation and BoC policy interest rates, among other factors, reflected a higher level of market risk compared to 2018.[32] Dr. Villadsen noted that Moody's Investors Service revised its outlook for the U.S. regulatory utility sector to negative because higher inflation may limit a utility's ability to recover its costs absent regulatory support.[33] All utility witnesses viewed high inflation as a risk factor contributing to higher capital costs.

39. J. Thygesen stated in his evidence that he interpreted the BoC Governor Tiff Macklem's comments as foreshadowing a pause in the central bank's policy interest rate increases and that lower inflation was expected.[34] EPCOR challenged this claim by noting that policy interest rates

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26 See, for example, the oral testimony of D. Madsen for IPCAA on this point at Transcript, Volume 2, page 505. See also, Exhibit 27084-X0918, IPCAA argument, PDF page 18.

27 Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

28 Exhibit 27084-X0921, ATCO Electric Ltd. - The Utilities Argument, June 6, 2023, PDF page 5, paragraph 13.

29 Exhibit 27084-X0921, ATCO Electric Ltd. - The Utilities Argument, June 6, 2023, PDF page 5, paragraph 13.

30 The Commission notes that since the utilities submitted their argument on June 26, 2023, the BoC raised interest rates one additional time to 5.00% on July 12, 2023. Bank of Canada, https://www.bankofcanada.ca/core-functions/monetary-policy/key-interest-rate/

31 Exhibit 27084-X0743, ENMAX Power Corporation – Reply evidence Concentric, April 4, 2023, PDF page 18.

32 Exhibit 27084-X0390, AltaLink - EDTI evidence D'Ascendis written direct testimony, February 1, 2023, PDF page 120.

33 Exhibit 27084-X0469.01, The Utilities Evidence – Villadsen, May 26, 2023, PDF page 24.

34 Exhibit 27084-X0305, CCA evidence of Jan Thygesen, February 1, 2023, PDF page 10, paragraph 26.

had increased since J. Thygesen's evidence was submitted.[35] However, the Commission observes that inflation had, in fact, decreased in June 2023 from its June 2022 high.[36]

40. Dr. Cleary acknowledged that inflation was high in 2022, but argued that it peaked and that the BoC's expectation is for a return to sub three per cent inflation going forward. He supported his contention by stating that higher central bank policy interest rates are reducing inflationary pressures and, consequently, that central banks are now in the later stages of their quantitative tightening cycle.[37]

41. D. Madsen explained at the hearing that Alberta utilities are geographically and jurisdictionally constrained. Therefore, an Alberta-based utility's ability to recover its prudent costs is dependent on the regulator. His contention is that in a supportive regulatory environment, macroeconomic conditions do not materially affect a utility's ability to recover its costs and, therefore, a utility experiences no meaningful increase in risk due to inflation.[38]

4.2 Economic growth

42. Slower economic growth, due in part to the actions of the central banks, was another key issue identified by witnesses. Generally, all witnesses agreed that lower economic growth is likely in Canada in 2023 and 2024, with a higher probability of a recession.

43. The utility witnesses contended that investors are concerned about a recession, based on the current macroeconomic conditions. J. Coyne noted that the U.S. already experienced a technical recession in 2022, which demonstrated weaker fundamentals in the economy and that the BoC is projecting lower growth in 2023 and 2024.[39] J. Coyne also referred to the inverted yield curve – higher short-term bond yields than long-term bond yields in the U.S. and Canada – as an indicator of investor concerns about a recession.[40] D. D'Ascendis stated that recessions create more inherent risk for investors because negative economic growth may put at risk a commensurate return.[41] Dr. Villadsen cited the BoC's January 2023 Monetary Policy Report, which forecast Canada GDP growth of one per cent in 2023 and 1.8 per cent in 2024, which is lower than the 3.6 per cent growth experienced in 2022.[42] All utility witnesses argued that the macroeconomic uncertainty due to inflation and monetary tightening increases the cost of capital because the market is riskier in that state.

44. J. Thygesen agreed that while there is an elevated expectation of a recession in the U.S., citing the Conference Board, Federal Reserve St. Louis and Federal Reserve New York, were a recession to occur, some or all of the associated risks would be offset by lower interest rates.[43]

45. Dr. Cleary noted that Alberta's economic outlook was appreciably better than that of other provinces and, in fact, was unlikely to be recessionary. In support, he cited the Conference

35 Exhibit 27084-X0928, AltaLink and EPCOR Final Argument, June 26, 2023, paragraph 35.
36 Exhibit 27084-X0911, AltaLink and EPCOR Undertaking Appendix – Risk Measures Table Updated, June 8, 2023, worksheet 'Summary'.
37 Exhibit 27084-X0320.02, Cleary evidence, PDF page 25. Transcript, Volume 3, page 645, lines 13-18.
38 Transcript, Volume 2, page 505.
39 Exhibit 27084-X0315, Concentric evidence, PDF pages 31-35.
40 Exhibit 27084-X0585, Concentric Responses to UCA IRs, March 15, 2023, Concentric-UCA-2023FEB21-011.
41 Exhibit 27084-X0750, D'Ascendis rebuttal evidence PDF pages 18-19.
42 Exhibit 27084-X0469.01, Villadsen evidence, PDF page 22.
43 Exhibit 27084-X0736, Thygesen rebuttal evidence, PDF pages 15-17, paragraphs 40-42.

Board of Canada's December 2022 Alberta outlook, which predicts higher positive growth compared to the rest of Canada due to continued strength in the oil and gas sector.[44]

4.3 Bond yields

46. All witnesses agreed that as the BoC policy interest rate has increased, so too have bond yields – both corporate and government. There was also agreement among witnesses that the spread between A-rated utility bond yields and government bond yields (credit spread) has increased in the U.S. and Canada since 2018.

47. J. Coyne argued that the increased credit spread reflects investor concerns about the credit quality of utility bonds and general uncertainty about the broader economy.[45] Dr. Villadsen noted that the last time credit spreads were at this level or higher was in the spring of 2020 when the pandemic began riling financial markets, which is an indication of investor caution.[46] Dr. Cleary acknowledged that the credit spread is slightly higher than historical averages, measured since 2003.[47]

4.4 Capital markets

48. Over the course of the pandemic and into the recovery from it, Canadian and U.S. capital markets experienced volatility and, at times, counterintuitive results.

49. The utility witnesses argued that capital market volatility underwent periods of extreme flux during and after the pandemic due to complex market conditions, which reflected a greater level of investor uncertainty. D. D'Ascendis compared the average VIXI and VIX (indices that measure the Canadian and U.S. stock market's expectation of volatility) between 2018 and 2022, and observed that the indices were higher in 2022, reflecting increased volatility.[48] Dr. Villadsen explained that market volatility peaked during the early stages of the pandemic, declined from its pandemic highs, and increased again once the economy reopened.[49]

50. Dr. Cleary contended that in Canada the VIXI is currently below its normal range, while in the U.S. the VIX is slightly higher than usual.[50] He also pointed out that current corporate price earnings ratios and dividend yields are consistent with historical averages, suggesting that capital markets are healthy.[51]

5 Formulaic approach to determine ROE

5.1 The need for a formulaic approach to setting ROE

51. Over the past two decades, the Commission and its predecessors have employed various methodologies to set the approved ROE and deemed equity ratios. Prior to 2004, the

[44] Exhibit 27084-X0320.02, Cleary evidence, PDF page 33.
[45] Exhibit 27084-X0743, Concentric rebuttal evidence, PDF pages 22-23.
[46] Exhibit 27084-X0469.01, Villadsen evidence, PDF page 33.
[47] Exhibit 27084-X0320.02, Cleary evidence, PDF page 20.
[48] Exhibit 27084-X0390, D'Ascendis evidence, PDF page 120.
[49] Exhibit 27084-X0469.01, Villadsen evidence, PDF page 35.
[50] Exhibit 27084-X0320.02, Cleary evidence, PDF page 23. Note that Dr. Cleary refers to the VIXI as the "Canadian VIX."
[51] Exhibit 27084-X0320.02, Cleary evidence, PDF page 22.

Commission's predecessors determined these parameters individually for each utility on a case-by-case basis.

52. In 2004, the Alberta Energy and Utilities Board (EUB), predecessor to the Commission, established a uniform (generic) ROE rate for all utilities and introduced a formulaic approach to determine subsequent ROE values.[52] This formulaic approach was used from 2005 to 2008. As a result of the global financial crisis in 2008-2009, in Decision 2009-216, the Commission discontinued the formulaic approach because it produced results that no longer accurately reflected changes in market circumstances. Specifically, the Commission observed that during the financial crisis, the traditional relationship between the risk-free rate and the required market return, on which the formulaic approach was based, did not hold.[53]

53. From 2009 through 2020, the Commission determined the ROE and deemed equity ratios by relying on evidence presented by parties in the GCOC proceedings. In doing so, the Commission retained the practice established in 2004 of setting a generic ROE for all utilities and accounting for any differences in business risks among the utilities through the deemed equity ratios. These parameters were established through rigorous regulatory proceedings, which included extensive oral hearings, where parties submitted a wide spectrum of economic and financial evidence. For the period 2021 to 2023, the Commission did not have fully litigated GCOC proceedings. Rather, it maintained the ROE of 8.5 per cent and a deemed equity ratio of 37 per cent (39 per cent for Apex) in light of the uncertainty arising from the pandemic and the limited access to stable, reliable, current and forward-looking economic and market data at the time.

54. Even though the Commission discontinued the formula in Decision 2009-216, it indicated that, to reduce regulatory burden, it would not "preclude a return to some sort of formula-based adjustment mechanism in the future when relationships in the capital markets have stabilized and are once again considered reasonably predictable."[54] After the effects of the 2008 financial crisis had abated, the Commission revisited the idea of implementing an ROE formulaic approach in almost every subsequent GCOC proceeding. However, in each of those instances, the Commission determined that a return to an ROE formulaic approach was not warranted. In earlier GCOC proceedings, this was due to the remaining volatility in the markets[55] and abnormal risk-return relationship attributable to ultra-low interest rates.[56] In later GCOC proceedings, the key obstacle was the onset of the pandemic and its associated economic dislocations.[57] Nevertheless, in every GCOC decision the Commission expressed its continued interest in exploring the reinstatement of an ROE formulaic approach given its administrative efficiency.

55. The Commission initiated the current proceeding with the view that a formulaic approach could offer a substantial improvement in efficiency with no loss in rigour or objectivity in determining the ROE component of the utilities' fair return. The fact that many jurisdictions have already adopted such an approach supported the Commission's view. In its directions on

52 Decision 2004-052.
53 Decision 2009-216, paragraph 417.
54 Decision 2009-216, paragraph 422.
55 Decision 2011-474, paragraph 165.
56 Decision 2191-D01-2015, paragraph 411.
57 Decision 24110-D01-2020: 2021 Generic Cost of Capital, Proceeding 24110, October 13, 2020, paragraphs 5, 7. Decision 26212-D01-2021: 2022 Generic Cost of Capital, Proceeding 26212, March 4, 2021, paragraph 18.

procedure letter,[58] the Commission asked whether ERP-based formulaic approaches, such as those adopted by the Ontario Energy Board (OEB) and the Commission's predecessor, the EUB, were an appropriate starting point for considering the reintroduction of an ROE formulaic approach in Alberta.

56. Most, if not all parties to this proceeding, were relatively unenthusiastic about, if not rather firmly opposed to, any Commission departure from holding periodic, fully litigated GCOC proceedings and moving instead towards adopting a formulaic approach for setting the ROE in 2024 and subsequent years. Nonetheless, over the course of this proceeding, parties were helpful to the Commission and provided their recommendations on specific parameters of a formulaic approach should the Commission ultimately decide to implement one, even though this was not their preference.

57. After considering various perspectives and parties' views, the Commission finds it will implement the formulaic approach for determining the ROE, starting in 2024. For the reasons set out below, the Commission is of the view that this approach offers a balanced and pragmatic solution to several pressing concerns.

58. Among the most important advantages of adopting a formulaic approach is the elimination of regulatory lag in establishing regulated rates. By setting the approved ROE on a prospective basis, the formulaic approach avoids delays, ensures that rates better reflect current economic conditions, offers greater regulatory certainty to utilities and customers alike, mitigates the risk of adverse credit rating actions, and reduces volatility in cash flows. Every one of these concerns has been raised by parties in past GCOC proceedings, including the most recent fully litigated one in 2018, as being among the negative consequences of regulatory lag.[59]

59. Furthermore, the formulaic approach enhances transparency and predictability in the regulatory process. It streamlines decision making by providing a clear and objective mechanism for determining the approved ROE, while reducing the need for protracted, resource-intensive, and costly litigated proceedings.[60] By doing so, it not only saves significant time and resources for both customers and utilities, but also aligns with the Commission's broader goal of improving efficiency and reducing regulatory burden.

60. The Commission reaffirms its commitment to exercising regulatory judgment, addressing concerns expressed by many parties that there must be an opportunity to review the ROEs produced by the formulaic approach for reasonableness as a safety feature. Should any party determine that the formulaic approach no longer results in just and reasonable outcomes, Section 5.4 below outlines a mechanism by which parties can apply to the Commission for corrective action.

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58 Exhibit 27084-X0034, paragraph 9.

59 Decision 22570-D01-2018, Section 9.3.2.4, Regulatory lag.

60 For example, for the most recent fully contested GCOC proceeding in 2018, the Commission approved cost awards amounting to just over $1.5 million. The Commission's scale of costs does not cover the full costs of most experts and legal counsel for proceedings, and the amounts claimed and awarded therefore do not reflect the real cost of participation. A review of actual invoices submitted in the 2018 GCOC costs proceeding indicates that parties to that proceeding spent a total of about $4 million on external legal counsel and experts. This does not account for the significant costs incurred by the parties internally, nor the costs of other parties (such as the UCA) who do not submit cost claims to the Commission, nor the costs of the Commission itself and its processes (costs which are ultimately borne by customers).

61. The record in this proceeding is clear that a variety of formulaic approaches are used in other jurisdictions. Experience in these jurisdictions, notably Ontario, suggests that a properly calibrated formulaic approach can operate effectively over a sustained period of time, producing ROE results that meet the fair return standard, without the associated costs and complexities of a fully litigated process. If a formulaic approach produces reasonable outcomes and its adoption avoids one or two exhaustive fully litigated proceedings, thereby contributing to the reduction in regulatory burden and cost, this would be a significant advancement compared to the current approach of initiating litigated cases every two to three years.

5.2 ROE formulaic approach

62. As noted in the previous section, in its directions on procedure letter,[61] the Commission put to parties the ERP-based formulaic approaches adopted by the EUB and the OEB as possible starting points for reintroducing an ROE formulaic approach.

63. In Decision 2004-052, the EUB adopted a single-factor formulaic approach for setting the generic ROE based on 75 per cent of the change in long-term GoC bond yield:

$$ROE_t = 9.60\% + 0.75 \times (YLD_t - 5.68\%)$$

64. The EUB established a generic ROE for the year 2004 at 9.60 per cent, which served as the initial or "base" ROE value in the above formula. An adjustment factor of 0.75 was determined through an assessment of the proposals submitted by the involved parties at the time. The final element of the formula encapsulated variation in forecast long-term Canada bond yield, calculated as the difference between the current year Consensus Forecasts[62] (denoted as YLD_t in the formula above) and the "base" yield of 5.68 per cent that was set based on forecasts deemed reasonable in the 2004 decision.

65. In its Decision EB-2009-0084,[63] the OEB approved the following formula:

$$ROE_t = 9.75\% + 0.5 \times (\mathrm{LCBF}_t - 4.25\%) + 0.5 \times (\mathrm{UtilBondSpread}_t - 1.415\%)$$

66. The OEB's formula established a "base" ROE of 9.75 per cent for the year 2010. The OEB approved an adjustment factor of 0.5 with respect to changes in long-term GoC bond yield, reducing it from the previously established value of 0.75. This change was made to decrease the formula's sensitivity to changes in government bond yields, which could be influenced by monetary and fiscal conditions unrelated to shifts in the utility cost of equity. In addition, the OEB acknowledged the existence of a statistically significant correlation between corporate bond yields and the cost of equity, and incorporated an element related to utility bond yields with an adjustment factor of 0.5.

67. As discussed in the previous section, while no utility witnesses expressly supported the use of a formula to determine the ROE, they provided evidence on specifications for a formulaic

61 Exhibit 27084-X0034, paragraph 9.
62 Consensus Forecasts are published by Consensus Economics.
63 Ontario Energy Board Decision EB-2009-0084: Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009.

approach should the Commission decide to proceed with one. Such evidence was also provided by the customer groups to a certain degree.[64]

68. Concentric indicated that, "If the AUC decides on an ERP approach, then the formula used in Ontario that includes both government bond yields and utility credit spreads is a reasonable compromise."[65] D. Madsen[66] expressed a similar view. As well, Dr. Villadsen recommended that changes in the long GoC bond yield and changes in the utility bond yield spread be included in the formula, much as they are in the OEB's methodology, as both factors influence the cost of equity.[67]

69. D. D'Ascendis found an ERP-based approach to be a suitable starting point for developing a formula to adjust an appropriately derived "base" ROE. Of the two examples set forth by the Commission, he found the OEB's two-factor adjustment formula to be superior to the one-factor adjustment formula used by the EUB, as it more closely reflects the relationship between interest rates and the ERP.[68] However, in his evidence, D. D'Ascendis recommended that the Commission broaden the basis of the ROE adjustment mechanism and use market data in the DCF model and capital asset pricing model (CAPM) for a group of risk comparable companies in lieu of a simple ERP model that is based on the change in bond yields.[69]

70. In his evidence, Dr. Cleary, submitted that the ERP-based approach is the most suitable formulaic method for determining allowable ROEs. He asserted that this approach is widely adopted and, in his perspective, it stands as the sole viable option. Furthermore, Dr. Cleary underscored that the OEB formula can be viewed, in essence, as a modified version of two ERP models, namely the CAPM and bond yield plus risk premium, which are commonly relied upon in assessing the cost of equity, or the approved ROEs, during cost-of-capital hearings.[70]

71. Based on the submissions of parties, the Commission adopts an ERP-based two-factor formulaic approach similar to the one utilized by the OEB. Specifically, the Commission approves the following two-factor formula to determine the ROE for 2024 and future test periods on an annual basis:

$$ROE_t = ROE_{base} + w_1(YLD_t - YLD_{base}) + w_2(\mathrm{SPRD}_t - SPRD_{base})$$

where:

ROE_t is the approved ROE for the test year t

ROE_{base} is the "base" ROE, that is the approved notional ROE

w_1, w_2 are adjustment factors for changes in long-term GoC bond yield and utility bond yield spread, respectively (referred to on the record as VAR4 and VAR7)

64 The CCA did not provide evidence regarding each variable of the two-factor formula.
65 Exhibit 27084-X0315, PDF page 21.
66 Exhibit 27084-X0292, PDF page 6.
67 Exhibit 27084-X0469.01, PDF page 9.
68 Exhibit 27084-X0047, PDF page 5.
69 Exhibit 27084-X0057, PDF pages 9-10.
70 Exhibit 27084-X0320.02, PDF pages 91-92.

YLD_t and YLD_{base} are long-term GoC bond yields for the test year and base period, respectively (VAR2 and VAR1)

$SPRD_t$ and $SPRD_{base}$ are utility bond yield spreads for the test year and base period, respectively (VAR6 and VAR5)

72. Based on the approvals in Section 6 of this decision, the generalized formulaic approach above can be specified as follows:

$$ROE_t = 9.0\% + 0.5 \times (\text{YLD}_t - 3.10\%) + 0.5 \times (\text{SPRD}_t - \text{SPRD}_{base})$$ [71]

73. In Decision 2011-474,[72] the Commission noted that this type of a formula has advantages over the previously utilized single-factor formula, as it is likely to better reflect any fluctuations in capital market conditions.[73] Based on the record of this proceeding, the Commission maintains this view.

74. Parties in this proceeding highlighted that the introduction of the utility bond yield spread component was a major improvement to the OEB formula that contributed to its longevity and acceptance of the resulting ROEs. Dr. Villadsen stated academic literature supports the basic concept that changes in credit spreads serve as a meaningful directional indicator of relative changes in the prevailing market equity risk premium.[74] Concentric indicated that the OEB formula has generally provided a more reasonable return in most of the years since the utility bond yield spread component was introduced because it captures industry-specific changes in risk that are otherwise not captured by changes in the government or risk free bond yield.[75] N. Martin pointed out the only review that the OEB conducted since 2009 was completed in 2016 and did not result in any change.[76] The Commission agrees with all of these observations.

5.3 Annual process to determine the ROE through the formulaic approach

75. From 2005 to 2008 when the EUB used a formula, the EUB initiated a proceeding every year to calculate the approved ROE for the subsequent test year beginning January 1. The EUB relied on the forecast 10-year Canada bond yield for a test year published in the Consensus Forecasts issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.[77] The results of the update were made available to the public by way of an order released at or near the end of November each year.

76. A similar process is used by the OEB to update its two-factor formula adopted in EB 2009-0084. More specifically, the cost-of-capital parameters are based on the data for September of the preceding year (i.e., three months in advance of the January 1 effective date for

71 The Commission has determined that it will use the bond yield spread for the month of February 2023, using the method set out in Section 6.5.3 of this decision.
72 Decision 2011-474: 2011 Generic Cost of Capital, Proceeding 833, Application 1606549, December 8, 2011.
73 Decision 2011-474, paragraphs 164-165.
74 Exhibit 27084-X0469.01, PDF page 80.
75 Exhibit 27084-X0315, PDF page 110.
76 Exhibit 27084-X0316, PDF page 31.
77 Decision 2004-052, PDF page 36.

rates), using the long-term GoC bond forecast and A-rated utility bond yield spread. The results of the update are made available to the public during the months of October to November.

77. In this proceeding, parties generally favoured the approach currently taken by the OEB[78] or the annual update process previously adopted by the EUB.[79] Overall, parties emphasized the need for transparency in the calculations with the results being made available to the public in advance of the ROE taking effect.

78. Given the preference of parties, and to reduce regulatory burden, the Commission will adopt a practice similar to the one it employed between 2005 and 2008. The Commission will initiate a proceeding in early November of each year, in which it will provide calculations of the upcoming year's ROE based on the October data for the forecast long-term GoC bond yield and prevailing utility bond yield spread in comparison to their base values. More specifically, as set out in Section 6.5:

(i) The forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield[80] over the period October 1 to October 31 each year preceding the test year (0.25 weight). In other words, the published forecasts and actual data in October 2023 will be used to set the ROE for 2024, data from October 2024 will be used to set the ROE for 2025, and so on.

(ii) The prevailing utility bond yield spread will be calculated as the average difference between the 30-year A-rated Canadian utility bond yield[81] and the long-term GoC bond yield[82] over the period October 1 to October 31 of the year preceding the test year (i.e., the utility bond yield spread in October 2023 will be used to determine the ROE for 2024, and so on).

79. Parties will have the opportunity to comment on the Commission's ROE calculations and provide input on any identified discrepancies. The Commission will then issue a decision at the end of November with a final approved ROE for the upcoming year resulting from the formulaic approach approved in this decision.

80. The ROE calculated by the formulaic approach for each test year will come into effect on January 1 of that year.

5.4 Periodic reviews of formulaic approach

81. Employing a formulaic approach to determine annual changes in the ROE requires periodic evaluation to ensure that the ROE produced by the formula continues to be in alignment with the standards for achieving a fair return.

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78 Exhibit 27084-X0292, PDF pages 51-52. Exhibit 27084-X0315, PDF page 116. Exhibit 27084-X0320.02, PDF page 12, and Section 5, PDF pages 91-98.
79 Exhibit 27084-X0469.01, PDF page 105. Exhibit 27084-X0390, PDF page 117.
80 Bank of Canada CANSIM Series V39056.
81 Bloomberg Series C29530Y.
82 Bank of Canada CANSIM Series V39056.

82. The Commission solicited input on the process to assess whether the formulaic approach continues to generate a reasonable ROE. The Commission also sought parties' views, should questions arise as to the continued reasonableness of the results produced by the formulaic approach, on necessary remedial steps to be taken to ensure that an ROE satisfying the fair return standard is restored on a go-forward basis.

83. In their submissions, parties identified two main approaches to reviewing the reasonableness of the ROEs produced by the formulaic approach. The first approach involves a predetermined periodic review of the ROEs determined formulaically, every three to five years, regardless of economic conditions. The second approach contemplates mid-term reopeners initiated either by the Commission or upon application by any interested party (i.e., utility or intervener). In the case of mid-term review applications filed by interested parties, the burden of establishing that a full scale review of the reasonableness of the formula's results is warranted would reside with the applicant. As a variant of the second approach, some parties proposed proactively adopting measures such as deadbands, ceilings and floors around the ROE in order to accomplish the following ends: (i) automatically trigger reopeners when formulaic outcomes depart from the previous year's results by a specified margin; and (ii) limit potentially frivolous review applications for relatively minor changes in ROE results from one year to the next.[83] Other parties recommended that the Commission refrain from prescribing fixed thresholds for reviewing formula results and, instead, retain the discretion to review the ROEs resulting from the formulaic approach as and when required.[84]

84. In the Commission's view, the two approaches are not mutually exclusive and elements of both can be employed to ensure that the formulaic approach continues to produce just and reasonable results.

85. The Commission has determined that a periodic review every five years strikes an optimal balance. This duration ensures the ongoing alignment of the formula-derived ROE with the established fair return standard, while maintaining the objectives of regulatory efficiency and certainty. The Commission emphasizes that this review process does not necessarily imply a fully litigated GCOC process resulting in a resetting of the formula's parameters, including base ROE. Rather, the Commission will initially seek input from parties on the preliminary assessment of the formula's continued capacity to generate a fair ROE. The Commission's decision on whether to undertake a comprehensive review of either the ROE in general, or the ROE formulaic approach in particular, will be informed by the feedback received on the preliminary matters. The Commission will retain full discretion in determining the process to be followed.

86. In line with this approach, the Commission expects to conduct its first assessment in 2028. Any modifications resulting from this evaluation will subsequently influence the ROE for the 2029 rate year and beyond.

87. In addition to providing for mandatory five-year reviews (without predetermining in advance the length, scope or complexity of the review process), the Commission also sees merit in allowing for mid-term reopeners either at its own initiative or upon application by interested parties if there are compelling grounds to believe that the ROE resulting from the formulaic

83 Exhibit 27084-X0924, ENMAX argument, PDF page 31, paragraphs 141-142. Exhibit 27084-X0926, UCA argument, PDF page 34, paragraph 123.

84 Exhibit 27084-X0928, AltaLink/EPCOR argument, PDF page 28, paragraph 73.

approach may no longer be just and reasonable. The Commission envisions mid-term reopeners initiated by parties would be subject to a two-stage review process. In order to move from Stage 1 to Stage 2 of the review process, applicants would bear the burden of establishing on a balance of probabilities that there exist one or more sufficiently compelling reasons for the Commission to question whether its formulaic approach to setting utility ROEs remains, and/or produces results that continue to be, just and reasonable. In the Commission's view, reliance on such a test is likely to quickly dispense with frivolous applications, while still allowing for a broad range of concerns that would justify a deeper examination of the continued reasonableness of the formulaic approach.

88. The Commission is not persuaded, however, that the potential benefits of establishing thresholds that would automatically trigger offramps for, or reasonableness reviews of, the formulaic approach outweigh the disadvantages of adopting such measures. As noted by AltaLink/EPCOR and Dr. Cleary, respectively: the "Commission should not attempt to predetermine and fix specific thresholds for reopeners or offramps"[85] and "given the difficulty capturing all scenarios where a review may be warranted, the need for a reopener may ultimately be best left to a matter of judgment."[86] In addition, the Commission notes that it has been almost 15 years since it last relied on a formulaic approach to set utility ROEs. The formulaic approach approved in this decision is also different from the last formula relied on by the Commission. As a result, the Commission considers it to be in the public interest – at least until it acquires greater familiarity with how the formula operates under a variety of different circumstances – that the Commission maintain the maximum degree of discretion in determining how and when the formulaic approach should be reviewed when a question arises as to its ability to meet the fair return standard both over time and in light of ever-changing market conditions.

89. Closely related, the Commission is concerned that any mechanical reliance upon predetermined ROE deadbands, ceilings and floors may inadvertently result in both false-positives (i.e., conducting unnecessary reviews) and false-negatives (i.e., failing to undertake necessary reviews).

5.5 Periodic reviews of deemed equity ratios

90. In order to meet the fair return standard, the Commission has to not only establish a fair ROE, but also determine which proportion of capital invested by the utilities should be financed through shareholder equity and which should be financed through debt. The proportion of capital to be financed by equity is referred to as the "deemed equity ratio." This represents that portion of total invested capital upon which a utility is allowed to earn its Commission-determined target rate of return. The Commission's findings on the approved deemed equity ratios for Alberta utilities are set out in Section 7 of this decision. In this section, the Commission addresses how often these approved ratios should undergo a reasonableness review.

91. The Commission solicited input from parties on whether it was necessary to update deemed equity ratios while a formulaic approach to determine ROE is in operation and, if so, how frequently and pursuant to what process.

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85 Exhibit 27084-X0928, AltaLink/EPCOR argument, PDF page 28, paragraph 73.
86 Exhibit 27084-X0926, PDF page 34, paragraph 124.

92. Consistent with the timing recommended for mandatory reviews of the continued reasonableness of formulaically updated ROEs, experts for several parties (including J. Coyne,[87] D. D'Ascendis,[88] Dr. Villadsen[89] and Dr. Cleary[90]) suggested that the reasonableness of deemed equity ratios also be reviewed at the same time (i.e., every three to five years). R. Bell, meanwhile, suggested that equity thickness be reviewed each year concurrently with the formulaic update to ROEs, while D. Madsen proposed several specific conditions for updating equity thickness ratios going forward.

93. The Commission acknowledges the importance of ensuring predictability of the approved level of the deemed equity ratios moving forward, particularly while utilizing a formulaic approach to determine ROE. Since the deemed equity ratio influences the financial structure of a utility and, therefore, the ROE calculation, the Commission agrees with those parties that advocated for a concurrent review of both elements.

94. The Commission does not consider an annual assessment of deemed equity ratios as proposed by R. Bell to be warranted or cost-justified. Similarly, the Commission does not find merit in imposing upon electric (and presumably, gas) utilities the many conditions D. Madsen[91] recommended be satisfied before new equity ratios can be approved.

95. Instead, the Commission will institute a mandatory review of deemed equity ratios every five years consistent – and contemporaneous – with the approach outlined in Section 5.4 that the Commission will employ for the periodic evaluation of the formulaic approach. As with the latter, the length, scope and complexity of the equity thickness review process will not be predetermined but, rather, will depend on circumstances prevailing at that time.

96. Additionally, the Commission recognizes the value of permitting mid-term reopeners, either at its own discretion or upon application of interested parties, if compelling circumstances suggest that the deemed equity ratio is no longer reasonable. When initiated by parties other than the Commission, such mid-term reopeners will be subject to a two-stage review process similar to that for reviews of the formulaic approach.

6 Notional ROE and other formula variables

6.1 Overview

97. The Commission must determine a fair return for the utilities under its jurisdiction as part of fixing just and reasonable rates. In Section 5 of this decision, the Commission determines that it will adopt a formulaic approach to setting the ROE starting in 2024. As also set out in that section, the formula requires a notional ROE as a starting point. This notional ROE is determined with the same rigour and process used to determine ROE in prior fully litigated proceedings, and considers a variety of approaches, models and directional indices. However, this ROE will not be reflected in customer rates; rather, its sole purpose is to serve as an input to the approved

87 Exhibit 27084-X0315, PDF page 7.
88 Exhibit 27084-X0390, PDF page 118.
89 Exhibit 27084-X0469, PDF pages 32-33.
90 Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 13, lines 17-19.
91 Exhibit 27084-X0292, PDF page 65.

formula. The ROEs produced by the formula will be approved on a final basis effective January 1 of each test year.

98. This section is organized as follows. In Section 6.2, the Commission discusses the extent to which the market data for the comparator group of utilities can be used to inform the determination of cost-of-capital parameters for the Alberta utilities. Section 6.3 determines a risk-free rate as an input to the ERP models, such as the CAPM, and the formulaic approach adopted by the Commission in this decision. In Section 6.4, the Commission determines the notional ROE by analyzing results of various financial models that were presented by proceeding participants. Finally, in Section 6.5, the Commission determines the values for the first and second factors of the formulaic approach to account for changes in GoC bond yields and changes in utility bond yield spread.

6.2 Comparability of representative utilities

99. In past GCOC proceedings, the Commission has frequently expressed concern with the wide range of conflicting evidence and polarized opinions on how it should approach setting a fair return on capital for the utilities it regulates. Oftentimes there was prolonged debate on the degree to which various utility comparator groups that parties relied on to construct models to estimate the ROE were representative of the Alberta utilities. An example of this is the 2018 GCOC proceeding, where parties proposed at least 13 different proxy groups consisting of various subsets of North American utilities.[92]

100. In order to address these concerns the Commission implemented a process to establish a comparator group of representative utilities that are similar to the Alberta utilities, for the purpose of informing the data-driven analysis required to specify the initial numerical variables of a formula-based approach to setting the ROE (the comparator group process).[93] The outcome of the comparator group process was that the parties reached a consensus on screening criteria and a comparator group of representative utilities resulting from the application of the screening criteria.[94]

101. The weight to be assigned to the specific utilities within the comparator group was not determined in the comparator group process. Instead, the Commission acknowledged that the parties did not agree that all companies in the comparator group are truly comparable to the Alberta utilities, and confirmed that the comparability of and weight to be assigned to the specific companies in the comparator group remained an issue to be determined in the proceeding.[95] The Commission specifically noted that parties could present evidence that certain companies in the comparator group should not be given any weight at all.[96]

102. The Commission is not persuaded by the argument that certain of the representative utilities in the comparator group lack comparability due to the involvement of their parent corporations in generation, retail or other unregulated business sectors. Concerns of this nature

[92] Exhibit 27084-X0038, paragraph 8.
[93] Exhibit 27084-X0034, paragraph 8.
[94] Exhibit 27084-X0268.01, PDF page 4.
[95] Exhibit 27084-X0239.01, PDF page 1, paragraph 2; Exhibit 27084-X0255, PDF page 4, paragraph 12; Exhibit 27084-X0268.01, PDF page 4.
[96] Exhibit 27084-X0255, PDF page 4, paragraph 12.

were addressed by the screening criterion, which excluded utilities from the comparator group if less than 80 per cent of their assets are tied to rate-regulated activities.

103. While the Commission finds that the U.S. companies have higher business risks than the Alberta utilities, for the purpose of establishing the comparator group, the Commission accepts the utilities' evidence that it is appropriate to include U.S. utility holding companies. The reasons for this are: (i) the relatively limited number of publicly traded Canadian utility companies; (ii) the prevalence of U.S. business operations among many publicly traded Canadian utilities; and (iii) investors' tendency to consider utility investment opportunities in both the U.S. and Canada.[97] Further, the Commission remains of the view that it is reasonable to consider the U.S. market return data given the globalization of the world economy and integration of North American capital markets.[98] Notwithstanding these findings, none of the Alberta utilities raises capital directly in the equity market, or operates outside of Alberta unlike a number of companies in the comparator group, which are holding companies and can operate anywhere.

104. After considering the evidence presented in this proceeding, the Commission acknowledges the utilities in the comparator group are not identical to the Alberta utilities, but concludes they are sufficiently comparable for use in various financial models. However, and as set out in in this section and Section 6.4.5, the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities. Accordingly, the Commission retains the view expressed in the 2018 GCOC decision that a significant amount of judgment must be applied by the Commission when interpreting data from the representative utilities to establish the ROE required by investors in the Alberta utilities.[99]

6.3 Measure of the risk-free rate

105. The risk-free rate is an important component of ERP models, such as the CAPM, and the formulaic approach approved by the Commission in Section 5. ERP-based models are based on the fundamental assumption investors require higher returns for bearing higher risk; or, in other words, investors require a premium for bearing risk that exceeds the risk-free rate. The Commission has accepted in the past that there is an inverse relationship between the risk-free rate and the risk premium required by equity investors: as interest rates increase (decrease), risk premium decreases (increases).

106. Consequently, given these fundamental relationships inherent in ERP-based models, the risk-free rate of 3.10 per cent approved in this section is used for three purposes in this decision: (i) as a base forecast long-term GoC bond yield (YLD_{base}) against which future expected changes in risk-free rates are measured to adjust the ROE in accordance with the approved formula; (ii) as a factor to determine the base ERP underlying the approved formula; and (iii) a measure of the risk-free rate in the CAPM model used to estimate the notional ROE.

107. Consistent with past GCOC proceedings, parties uniformly submitted that yields on long-term government bonds are considered to be default free and therefore are an appropriate measure of the risk-free rate. There was general agreement the 30-year Canada bond yield be

[97] Exhibit 27084-X0937, Utilities reply argument, PDF page 12, paragraph 32.
[98] Decision 22570-D01-2018, paragraph 275; Decision 20622-D01-2016: 2016 Generic Cost of Capital, Proceeding 20622, October 7, 2016, paragraph 302; Decision 2009-216, paragraph 200.
[99] Decision 22570-D01-2018, paragraph 275.

used, as the 30-year term to maturity is consistent with the long-term character of the underlying utility assets.

108. Parties were also consistent in the view that the bond yield used to approximate the risk-free rate be forward-looking, in keeping with the forward-looking nature of a cost-of-capital determination. However, there were differences in how the forecast 30-year Canada bond yield should be determined and the data sources used. Submissions of parties as to the forecast long-term GoC bond yield, term to maturity, and source of data are summarized below in Table 1.

Table 1. Risk-free rate recommendations

Witness (sponsoring party)	Recommendation	Data source	Yield
Dr. Villadsen (ATCO/Apex/Fortis)	Use projection of the 10-year Canada bond yield plus the long-term average maturity premium between 10-year and 30-year Canadian bonds.[100]	Consensus Economics[101]	3.85% as of November 7, 2022[102]
Concentric (ENMAX)	Use 10-year bond yield forecast and add the average spread between 10- and 30-year government bond yields.[103]	Consensus Economics	3.59%[104]
D. D'Ascendis (AltaLink/EPCOR)	Use an average of three-month-out and 12-month-out forecasts of the 30-year Canada bond yield.[105] [106]	RBC Financial Markets Monthly and TD Economics Forecast	2.89% as of December 31, 2022
D. Madsen (IPCAA)	Use current 30-year GoC bond yield as this point in time observation is consistent with a number of published forecasts of the 30-year Canada bond yield for 2023-2024.[107]	RBC Financial Markets Monthly, Kroll	2.95% as of January 13, 2023
Dr. Cleary (UCA)	Use the actual prevailing 30-year government bond yield at the time the initial (or base) ROE is set.[108]	-	2.85% as of January 19, 2023[109]
J. Thygesen (CCA)	No submission made on the rate or approach to quantify this variable.	-	Maximum risk-free rate for 2024 be set at 3%[110]

109. The Commission accepts the submissions of parties that the 30-year term to maturity best reflects the long-term character or useful life of the underlying utility assets. The Commission

[100] Exhibit 27084-X0469, PDF page 71.
[101] Consensus Economics publishes long-term [10-year] interest rate projections twice a year, in April and in October. Transcript, Volume 2, page 114, lines 2-6.
[102] Exhibit 27084-X0469, PDF page 41. 3.85% represents the average of yield on a 10-year Canadian government bond in February 2023 (3.5%) and November 2023 (3.4%) as reported by Consensus Forecasts on November 7, 2022, publication, adjusted upwards by Dr. Villadsen by 40 basis points to represent maturity premium for the 30-year over the 10-year Canadian government bond.
[103] Exhibit 27084-X0315, PDF page 101.
[104] Exhibit 27084-X0315, PDF page 61, Concentric evidence. While Concentric did not recommend a specific numerical value for the base forecast long-term GoC bond yield, it used an average of the Canadian (3.59%) and U.S. (3.87%) risk-free rates of 3.73% in its estimation of the notional ROE and implied ERP in its filed evidence.
[105] Exhibit 27084-X0390, PDF page 24.
[106] Exhibit 27084-X0610, AML_EPCOR-AUC-2023FEB21-001, PDF pages 1-3.
[107] Exhibit 27084-X0292, PDF page 14.
[108] Exhibit 27084-X0320.02, PDF pages 6-7.
[109] Exhibit 27084-X0605, UCA-AUC-2023FEB21-012, PDF page 31.
[110] Exhibit 27084-X0713, paragraph 44.

notes that parties provided various empirical and capital markets resources that supported the rationale for matching the useful life of the asset and the term to maturity of the risk-free rate.[111]

110. In keeping with the prospective or forward-looking nature of the determination of the cost of capital and prior Commission practice, it is appropriate to use a forecast of the 30-year Canada bond yield submitted on the record of this proceeding. The Commission finds that a direct forecast of the 30-year Canada bond yield from Canadian major banks is simpler and more transparent than the approach recommended by Dr. Villadsen and Concentric, which uses the Consensus Economics forecast 10-year GoC bond yield and adjusts it by adding the average spread between 10- and 30-year government bonds. The need for this adjustment arises from the fact that Consensus Economics, on which Dr. Villadsen and Concentric rely, does not publish a forecast for the 30-year Canada bond yield. Similar adjustments have been used by the OEB and EUB for their formulas because of reliance on Consensus Forecasts.

111. The 30-year Canada bond yield forecasts are published by large, reputable Canadian financial institutions such as “the Big Six” banks. In the Commission’s view, these forecasts are of comparable quality to the forecasts published by Consensus Economics. In fact, the Consensus Economics forecast is an average of estimates from various sources, including Canadian major banks. However, using direct forecasts of the 30-year Canada bond yield eliminates the need to make additional estimates and adjustments to the 10-year forecast for which there is no single, standardized approach. In addition, these forecasts are publicly available without cost. For simplicity, the Commission considers that averaging the forecasts from three banks, RBC, TD and Scotiabank, is sufficient. Should a forecast from one or more of these banks be unavailable, there are three additional major banks from which a forecast may be obtained as a substitute.

112. In addition to relying on bond yield forecasts published by the three banks, the Commission accepts in principle the approach of D. Madsen and Dr. Cleary to use a naïve forecast,[112] using the actual 30-year GoC bond yield to inform an estimate of the future 30-year GoC bond yield. The Commission has relied on this approach in past GCOC decisions to temper published forecasts because it accepted they tend to overestimate changes in interest rates. In this proceeding, representatives of customer groups made a similar point.[113] However, the Commission considers it is better to use the average actual long-term GoC bond yields for an entire month rather than the yield that prevailed on any a single day in that month, as was done by Dr. Cleary and D. Madsen, to smooth out the daily volatility.

113. The Commission will use the bank forecasts published in February 2023 provided by D. D’Ascendis, as they were the most recent bank forecasts of long-term GoC bond yields provided on the record. For consistency, the Commission will use the average actual long-term GoC bond yield in February 2023 for the naïve forecast.

114. For the reasons above, the Commission finds it reasonable to set the forecast risk-free rate to be 3.10 per cent, equal to the average of the 30-year Canada bond yield estimates for the forecast period Q1 2023 to Q4 2023 of RBC at 2.90 per cent, TD at 3.08 per cent, and

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[111] Exhibit 27084-X0390, D’Ascendis evidence, PDF pages 22-24.

[112] An estimating technique wherein the actual values from the previous period are employed as the forecast for the current period, without adjusting them or identifying causal factors.

[113] Exhibit 27084-X0292, Evidence of Dustin Madsen, PDF page 14; Exhibit 27084-X0320.02, Evidence of Dr. Cleary, PDF page 39.

Scotiabank at 3.26 per cent as of February 2023[114] as well as a naïve forecast of 3.16 per cent representing the average actual long-term GoC bond yield for the period February 1 to February 28, 2023.[115]

6.4 Notional ROE

115. In this section, the Commission determines the notional ROE of 9.0 per cent using current market data and considering results of well-known and widely accepted empirical models to estimate the required return such as the CAPM, constant growth discounted cash flow (DCF), and multi-stage DCF.

116. Under the formulaic approach, the notional ROE serves as the base metric against which future adjustments arising from changes in forecast long-term Canada bond yields and utility bond yield spreads are made and captures the estimated forecast ERP that is commensurate with the base forecast long-term GoC bond yield.[116] In turn, the notional ROE can be defined as the sum of the base forecast long GoC bond yield (YLD_{base} in the formula) and the base forecast ERP.

117. Parties recommended a notional ROE and estimated the ERP based on their respective risk-free-rate submissions. Table 2 sets out the notional ROE and ERP recommendations by party.

Table 2. Notional ROE and ERP recommendations by party

Witness (sponsoring party)	Notional ROE (%)	ERP[117] (%)	Empirical approaches used	Comments
Dr. Villadsen (ATCO/Apex/Fortis)[118]	10.0	5.68	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommended range for notional ROE is 9.2% to 10.4%
Concentric (ENMAX)	9.50	5.67	CAPM, DCF, M-DCF, Bond Yield Risk Premium Analysis	Recommendation reflects M-DCF and CAPM using historical MERP.[119]
D. D'Ascendis (AltaLink/EPCOR)	10.30	6.44	CAPM/ECAPM, DCF, M-DCF, Predictive Risk Premium Model, Adjusted Total Market Approach	Recommended range for notional ROE is 9.80% to 10.80%.[120]
D. Madsen (IPCAA)[121]	7.70	4.75	CAPM, DCF and M-DCF	Recommendation is simple average of CAPM and DCF models (7.51% and 7.90%)
Dr. Cleary (UCA)	6.75	3.90	CAPM, DCF, M-DCF and Utility Bond Risk Premium Analysis	-

114 Exhibit 27084-X0610, PDF page 2 with reference to Exhibit 27084-X0611 providing supporting data.
115 This is a Commission calculation using the Bank of Canada website provided in Exhibit 27084-X0613, UCA-UTILITIES-2023FEB21-008, PDF page 11. https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1010013901
116 Exhibit 27084-X0268.01, PDF page 3.
117 Includes 0.50% flotation allowance.
118 Exhibit 27084-X0921, PDF page 2. Recommendation also assumes 40% deemed equity for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, with additional equity thickness for ATCO Electric Transmission (42%), Apex (44%) and Fortis (43%). If deemed equity is set at 37%, then the ROE should be set 25 to 40 basis points above the recommendation for 40% equity or 10.25% to 10.40%. Recommended notional ROE and VAR3 include 20 basis point risk adder.
119 Exhibit 27084-X0315, PDF page 4. If deemed equity is set at 40%, then the ROE should be set at 10%.
120 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 9.
121 Exhibit 27084-X0292, PDF page 6.

118. As was the case in past GCOC proceedings, parties in this proceeding presented the Commission with a wide range of recommendations for notional ROE and ERP. In addition, there is significant variability in the results obtained by applying each of the empirical models, all of which have been previously considered by the Commission.

119. In sections 6.4.1 to 6.4.4 the Commission briefly describes the empirical models, including the key variables that must be specified and associated measurement issues. In Section 6.4.5, the Commission considers the results of the models and exercises its judgment, having regard to all of the evidence in this proceeding, to determine the notional ROE and ERP. The Commission's conclusion on the notional ROE for the formula takes into account that the Alberta utilities are at the low end of the range of risk present in the comparator group of utilities.

6.4.1 The CAPM

120. The CAPM is based on the relationship between the returns investors expect to receive on their investments in an asset and the systematic (or non-diversifiable) risk faced by that asset. The model is premised on a relationship where the required future return on the asset is proportional to that asset's risk relative to the market. This risk is measured by the asset's "beta."

121. The CAPM can be represented by the following formula:

$$Rs = Rf + \beta[Rm - Rf]$$

where:

Rs is the required return on the common stock;
Rf is the risk-free rate;
Rm is the return on the market portfolio;
Rm – Rf is the market equity risk premium (MERP); and
β, or beta, is the risk measure for the common stock.

122. Each of the variables in the CAPM equation must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The CAPM recommendations of parties are summarized in the following table.

Table 3. CAPM recommendations by party

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
D. D'Ascendis (AltaLink/EPCOR)[122]	2.88	7.64	0.61	0.50	8.38 (Canadian utility group)
	4.03	7.80	0.79	0.50	10.88 (U.S. electric utility group)
	4.03	7.80	0.76	0.50	10.70 (U.S. gas utility group)
Dr. Villadsen (ATCO/Apex/Fortis)[123]	3.85	5.91-6.56	37% Raw: 0.6-1.72 37% Blume: 0.51-1.54	-	9.81-11.76 (full comparator group)

[122] Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 86, 177-179. ROE results represent an average of CAPM and ECAPM models.

[123] Exhibit 27084-X0469.01 PDF pages 46-49; Exhibit 27084-X0460_C, BV-12(a) ROE Model - 40%; Exhibit 27084-X0461, BV-12(b) ROE Model - 37%; Exhibit 27084-X0689.01-C, ATCO/Apex/Fortis IR responses to the AUC, PDF pages 1-4. If deemed equity is set at 40%, Dr. Villadsen calculated betas ranging from 0.56 to 1.61.

Witness (sponsoring party)	Risk-free rate (%)	MERP (%)	Beta	Flotation allowance (%)	ROE (%)
			37% Hamada: 1.01-1.21		
Concentric (ENMAX)[124]	3.73	7.59	0.83-0.86	0.50	10.73 (full comparator group)
Dr. Cleary (UCA)[125]	2.85	5.00	0.45	0.50	5.7 (Canadian comparator group)
D. Madsen (IPCAA)[126]	2.95	6.08	0.669	0.50	7.51 (Canadian and U.S. electric utility group)

123. The Commission did not consider the empirical CAPM (ECAPM) approach to estimate the notional ROE or ERP, consistent with the Commission's previous approach.[127] The Commission accepts Dr. Cleary's concerns with the ECAPM[128] methodology, and that the assumptions and variables used in the approach were not subject to adequate testing in this proceeding.

6.4.1.2 CAPM inputs

Risk-free rate

124. In considering the parties' CAPM ROE results, the Commission took into account the extent to which parties' estimate of the risk-free rate differed from the 3.10 per cent rate that the Commission found reasonable in Section 6.3.

Beta

125. Beta captures the sensitivity of a stock's returns to the market's returns. It is a measure of systematic risk – general risk that cannot be diversified away. In effect, beta measures the contribution made by an individual stock to the risk of the diversified market portfolio.

126. Considerable academic and empirical evidence has been filed on the record of this proceeding to support the position taken by parties on how beta should be calculated. In general, witnesses for the utilities used betas that:

- were sourced from established fee-for-service data providers widely used by the investment community, in particular Value Line and Bloomberg;
- were based on weekly data on the premise that more frequent observations better capture the contribution made by each individual stock in the comparator group of equities to the

[124] Exhibit 27084-X0315, Concentric evidence, PDF pages 62, 64-65, 105. The betas used in Concentric's CAPM analyses for the entire comparator group are drawn from two sources: Value Line and Bloomberg. The MERP value of 7.59 represents an average of Canadian and U.S., historical and forward-looking values.

[125] Exhibit 27084-X0320.02, Cleary evidence, PDF page 61. Beta of 0.45% is raw/unadjusted. ROE of 5.7% includes an A-rated Canadian utility bond yield spread adjustment of 0.095%.

[126] Exhibit 27084-X0292, Madsen evidence, PDF pages 28-29.

[127] Decision 20622-D01-2016, paragraph 199.

[128] Exhibit 27084-X0759, Cleary evidence, PDF page 43-45.

risk of the diversified market portfolio over the measurement period. Selected measurement periods ranged from two[129] to five-years;[130]

- incorporated the Blume adjustment on the basis that it addresses the tendency of raw betas to change gradually over time, transforms historical unadjusted or raw betas into an expectational value consistent with the forward-looking nature of the cost of capital, and partially corrects for the known deficiencies of the CAPM;[131] and

- in the case of the evidence filed by Dr. Villadsen, used the Hamada adjustment to reflect a 40 per cent deemed equity component to standardize the capital structure of the comparable group of utilities and calculate beta[132] on an equivalent basis, given the relationship between financial leverage and equity returns.

127. For the consumer groups, Dr. Cleary and D. Madsen used a different approach to calculate beta:

- Dr. Cleary used weekly and monthly raw (unadjusted) betas for both the U.S. and Canadian comparators data from Bloomberg to arrive at an estimated beta of 0.45. Dr. Cleary did not support the use of either the Blume or Hamada adjustments to calculate beta.[133]

- D. Madsen used raw and adjusted betas in his analysis. He included Blume adjusted monthly betas on the basis that they are consistent with the forward-looking nature of a cost-of-capital determination. D. Madsen used five-year monthly data provided by YCharts and Yahoo Finance to determine an average adjusted beta of 0.669 for the combined Canadian and U.S. Electric Utility segments of the comparable group of utilities.[134] D. Madsen considered and then rejected the use of Blume adjusted, weekly Value Line betas.

128. In this proceeding, parties had much the same debates about beta as in past GCOC proceedings. Consistent with its views in past GCOC decisions, the Commission considers that there exists some room for legitimate differences of opinion among industry practitioners and academic experts on what constitutes a reasonable range for regulated utility betas.

129. For example, the Commission remains uncertain of the extent, if any, to which the Blume adjustment is warranted in determining betas for regulated utilities that face less risk than an average firm in the market. Indeed, there are ample reasons to question on what basis the

129 Transcript, Volume 5, page 973, lines 8-11 and 15, D'Ascendis evidence. D. D'Ascendis uses Bloomberg's default setting of two years to calculate beta.

130 Exhibit 27084-X0315, Concentric evidence, PDF page 62. Value Line publishes the historical beta for each company based on five years of weekly stock returns and uses the New York Stock Exchange as the market index. Concentric has computed Bloomberg betas using five years of weekly stock returns and using the S&P or the S&P/TSX Composite as the market index, in the case of U.S. or Canadian comparable equities, respectively.

131 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 76-84; Exhibit 27084-X0315, Concentric evidence, PDF pages 62-64; Exhibit 27084-X0047, Villadsen evidence, PDF pages 7-8; and Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44.

132 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 43-44. Dr. Villadsen used weekly data from Bloomberg over a three-year measurement period. A similar analysis was performed assuming deemed equity of 37%.

133 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 49-60 and Exhibit 27084-X0333, Cleary evidence.

134 Exhibit 27084-X0292, Madsen evidence, PDF pages 16-22.

systematic risks faced by regulated utilities might ever be expected to approach, much less exceed, those for the market as a whole, which is a central premise of the Blume adjustment.[135] Nevertheless, the Commission acknowledges that adjusted betas are widely used by finance professionals, as they provide useful information in certain circumstances.

130. As expressed in several past decisions, the Commission remains unpersuaded that adjusted betas are superior to raw betas in the context of regulated utilities. Rather, it finds that both raw and adjusted betas can provide useful information with respect to utility risk.[136] Similarly, the Commission continues to find that reliance on both weekly and monthly estimates of beta is reasonable.[137]

131. J. Coyne estimated beta to be 0.83 to 0.86,[138] while Dr. Villadsen calculated raw, Blume and Hamada adjusted betas, producing betas ranging from 0.51 to 1.72. Within this range Dr. Villadsen recommended for the Commission's approval a range of Hamada betas from 1.01 to 1.21.[139] The Commission finds these are unreasonably high given its findings regarding the overall risk of the Alberta utilities. More generally, the Commission does not accept that betas are understated for the utilities in the absence of the Hamada adjustment.

132. The Commission concludes that utility stocks are appreciably less risky and volatile than equities in the broader market, and therefore considers a reasonable range of betas for regulated gas and electric utilities to be between 0.45 (representing Dr. Cleary's unadjusted long-term beta) and 0.75 (in the range of adjusted betas recommended by D. Madsen[140] and D. D'Ascendis[141]). The high end of Dr. Villadsen's[142] beta estimates were well above this range.

Market equity risk premium

133. Parties to the proceeding used a variety of approaches to quantify the MERP.

134. D. Madsen's MERP of 6.08 per cent is an average of three MERP estimates: the implied MERP provided by Kroll of 6.0 per cent, Dr. Damodaran's implied MERP of 6.0 per cent as of January 1, 2023, and the implied MERP calculated by D. Madsen of 6.23 per cent by applying a Gordon Growth Model to the S&P500.[143]

135. Dr. Cleary adopted a MERP of 5.0 per cent, equal to the average of a commonly used historical range of 4 to 6 per cent. Dr. Cleary relied on a series of surveys and reports from academics, investment management firms, and actuarial service providers to establish historical and forecast returns for the Canadian, U.S. and world developed markets.[144]

136. Dr. Villadsen used the historical average premium of market returns over the long-term GoC bond yields, as per Duff & Phelps, for both Canada and the U.S. The MERP is expressed as

135 For a discussion of the history of Blume's adjustment and its limitations in the context of the regulated utility industry, see paragraph 164 of Decision 20622-D01-2016.
136 Decision 22570-D01-2018, paragraphs 345-346.
137 Decision 22570-D01-2018, PDF page 80, paragraph 344.
138 Exhibit 27084-X0315, Concentric evidence, PDF page 62.
139 Exhibit 27084-X0469.01, Villadsen evidence at PDF pages 46-48.
140 Exhibit 27084-X0292, Madsen evidence, PDF page 29.
141 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 80.
142 Exhibit 27084-X0469.01, PDF pages 46-49.
143 Exhibit 27084-X0292, Madsen evidence, PDF pages 24-29.
144 Exhibit 27094-X0320.02, Cleary evidence, PDF pages 39-49.

the arithmetic average and is 5.91 per cent for Canada (1935-2021) and 7.46 per cent for the U.S. (1926-2021). By adjusting Bloomberg forecast MERP for the spread between a 10-year and 30-year government bond yield, Dr. Villadsen also calculated a forecast MERP for Canada of 6.56 per cent and a lower number for the U.S. using proprietary data.[145]

137. D. D'Ascendis calculated a prospective MERP for both Canada and the U.S. by applying a constant growth DCF model to the companies comprising each of the S&P/TSX and S&P 500. The resulting total return for each index was then reduced by the forecast Canadian or U.S. long-term government bond yield. This produced forecast MERPs for Canada and the U.S. of 9.92 per cent and 7.03 per cent, respectively. D. D'Ascendis also estimated historical MERPs by using a regression analysis in which the MERP is expressed as a function of the long-term government bond yield. The historical MERPs for Canada and the U.S. using this approach were 5.35 per cent and 8.57 per cent, respectively.[146] The Commission notes that overall, D. D'Ascendis recommended MERPs of 7.64 for Canada and 7.80 for the U.S. as summarized in Table 3 above.

138. Concentric used the MERP ex-post historical arithmetic average based on data from Kroll of 5.74 per cent for Canada (1919-2021), and 7.46 per cent for the U.S. (1926-2021). Concentric, used an approach similar to that of D. D'Ascendis, to forecast MERPs of 9.22 per cent for Canada and 7.93 per cent for the U.S.[147] Concentric's recommended MERP, as set out in Table 3, is 7.59.

139. Parties developed their MERP recommendations using three general approaches or a combination of them. The first approach was to examine historical MERPs; that is, the difference between historical long-term realized stock market returns and the risk-free rate (as measured by long-term GoC bond yields) in Canada and the U.S. The Commission agrees that this approach is informative as it captures a large number of economic and monetary cycles and minimizes the risk that calculated MERPs reflect anomalous or transitory market conditions. The historical MERP values were approximately 6.0 per cent for Canada and 7.50 per cent for the U.S.

140. The second approach was to estimate prospective or forward-looking MERPs by relying on available market return estimates of investment management professionals and actuarial service providers, as was done by Dr. Cleary to arrive at a 4 to 6 per cent estimate and by Dr. Villadsen to arrive at a 5.91 to 6.56 per cent recommended MERP estimate.

141. The Commission recognizes that there may be pitfalls to relying on available forecasts of market return. For example, these estimates may not be as robust as empirical studies, or be amenable to ready analysis or testing, and may be prepared for different purposes; however, this type of evidence does offer some indication of what market professionals believe the ROE may be in the future. This can, and potentially does, affect investor expectations and subsequent behaviour. That, in itself, can shed light on the limits or frontiers of the range of reasonable estimates of the required ROE.

142. Under the third approach, parties estimated prospective MERPs by calculating expected market return. To do so, Concentric and D. D'Ascendis employed forecast earnings growth rates in excess of 9 per cent, which resulted in estimates for expected market returns ranging from

145 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 42-43. Exhibit 27084-X0458-C, Appendix BV-7 Bond Yields & MERP, tab "MRP calculation."
146 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 85.
147 Exhibit 27084-X0315, Concentric evidence, PDF pages 64-65.

10.4 per cent to 12.8 per cent for Canada and from 11.0 per cent to 11.8 per cent for the U.S. This, in turn, produced MERP estimates in the order of 9 to 10 per cent. Consistent with the findings in the 2018 GCOC decision, the Commission considers these estimates excessive, as they are based on calculated expected market returns that reflect unrealistically high earnings growth assumptions.

143. Given the above observations, the Commission notes that when the MERP estimates in the order of 9 per cent calculated by Concentric and D. D'Ascendis are excluded, the remaining MERP recommendations of the parties fall into what the Commission considers is a reasonable range of 5.9 per cent to 7.5 per cent.

Flotation allowance

144. In past GCOC proceedings, the Commission has accepted a flotation allowance of 0.50 per cent in estimates of ROE obtained from the application of the various models, including CAPM. The flotation allowance is normally included in the approved return to account for administrative costs and equity issuance costs, any impact of underpricing a new issue, and the potential for dilution.[148] No party opposed the use of 0.50 per cent for the flotation allowance. The Commission finds this flotation allowance continues to be reasonable for use in the financial models.

6.4.2 Constant growth DCF model

145. The constant growth DCF model assumes that the market price of a stock is equal to the present value of the cash flows that the owners of the shares expect to receive. In general, expected future cash flows are represented by the dividends paid per share. This pricing relationship is generally expressed as:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty}$$

where:

P_0 represents the current stock price;

D_1 … D_∞ represent expected future dividends; and

k (or K) is the discount rate or required ROE.[149]

146. Each of the variables in the DCF approach must be estimated, and there are a variety of different data sources and forecasting methods or approaches that could be used. The constant growth DCF recommendations by parties are summarized in Table 4.

148 Decision 22570-D01-2018, PDF page 104.
149 The expression can be simplified and rearranged into annual and quarterly compounding DCF equations: Exhibit 27084-X0292, Madsen evidence, PDF page 29.

Table 4. Constant growth DCF recommendation by party

Witness (sponsoring party)	ROE	Flotation allowance[150]	ROE including flotation allowance
	(%)		
D. D'Ascendis (AltaLink/EPCOR)[151]	10.21 (Canadian utilities) 9.34 (U.S. electric utilities) 10.01 (U.S. natural gas utilities)	0.50	10.71 (Canadian utilities) 9.84 (U.S. electric utilities) 10.51 (U.S. natural gas utilities)
Dr. Villadsen (ATCO/Apex/Fortis)[152]	12.79 (Canadian utilities) 9.38 (U.S. electric utilities) 9.66% (U.S. gas utilities)	0.50	13.29 (Canadian utilities) 9.88 (U.S. electric utilities) 10.16 (U.S. gas utilities)
Concentric (ENMAX)[153]	9.88 (Canadian proxy group) 9.43 (U.S. electric proxy group) 9.84 (U.S. gas proxy group) 9.59 (N.A. combined proxy group)	0.50	10.38 (Canadian proxy group) 9.93 (U.S. electric proxy group) 10.34 (U.S. gas proxy group) 10.09 (N.A. combined proxy group)
Dr. Cleary (UCA)[154]	6.35	0.50	6.85
D. Madsen (IPCAA)[155]	7.31-9.14	0.50	7.81-9.64

6.4.2.1 Constant growth DCF inputs

Current stock price

147. To estimate the current stock price input to the DCF model, most parties calculated the average closing price over a period ranging from 15 to 90 trading days ending between late December 2022 and late January 2023 to avoid biases that may arise over very short periods of time from anomalous or transitory events.[156]

148. The Commission accepts the use of an averaging period to calculate the current stock price to mitigate the risk that a single date, point-in-time estimate may be biased by market conditions on the pricing date. The averaging period should not exceed 90 days, as a longer averaging period would likely violate the empirical assumption that the constant growth DCF approach uses current stock prices. In addition, the Commission will accept the adjustment of the current quarterly dividend by the chosen dividend growth rate, as submitted by D. D'Ascendis, Dr. Villadsen and Concentric. No party provided a contrary view that the adjustment was inappropriate.[157]

150 The constant growth DCF directly calculates ROE prior to the addition of the flotation allowance.

151 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 47. Average of the mean and median.

152 Exhibit 27084-X0469.01, Villadsen evidence, PDF pages 54-55. Exhibit 27084-X0460-C, BV-12a, Villadsen evidence. ROE values are presented at 40% equity thickness.

153 Exhibit 27084-X0315, Concentric evidence, PDF pages 53-57. Exhibit 27084-X0490, Concentric evidence, sheet JMC-3 Constant DCF. ROE results represent mean values. Of note, Concentric's recommended ROE of 9.50% is based on the average of the multi-stage DCF model (not the constant growth DCF model).

154 Exhibit 27084-X0320.02, Cleary evidence, PDF page 71. Dr. Cleary used only the Canadian utilities in his recommendations.

155 Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Attachment 1, Madsen evidence, Tab "DCF." D. Madsen does not use the U.S. Gas utility comparable equities in his constant growth analysis and excludes Algonquin Power & Utilities Corp. from his DCF calculations.

156 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 42; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1, Exhibit 27084-X0292, Madsen evidence, PDF page 32.

157 The Commission notes that the constant growth DCF formula set out at the beginning of the section is taken from D. Madsen's evidence and clearly shows the adjustment of the dividend by the growth rate (footnote 55).

Dividend

149. The experts adopted slightly different approaches to how they calculated dividends. Most took the annualized dividend at year-end 2022 for each utility and then increased it quarterly or semi-annually by a fixed percentage of the forecast growth rate.[158] Dr. Cleary's approach was to provide a number of dividend yield calculations, including trailing 12-month dividend yields from December 2022 and average five-year and seven-year dividend yield averages.[159]

Dividend growth rate

150. Several of the experts relied on analysts' forecasts of company-specific dividend and earnings per share (EPS) growth rates.[160] D. Madsen also considered data from other sources and both he and Dr. Cleary[161] considered historical data. There was debate on whether dividend growth rates in the constant growth DCF analysis can the exceed the growth rate of the overall economy, as measured by the GDP growth rate. For example, D. Madsen said that, generally, dividend growth estimates should be below forecast growth in nominal GDP, while D. D'Ascendis did not agree with such limitation.

151. In past GCOC decisions the Commission rejected the use of dividend growth rates that exceeded estimates of the nominal long-term GDP growth rate. In this proceeding, Concentric filed evidence that earnings and dividend growth have exceeded GDP between 2007 and 2021 in support of the proposition that analyst estimates of growth rates above GDP are reasonable.[162] D. D'Ascendis indicated that the compound annual utility industry EPS growth rate of 6.53 per cent exceeded the U.S. GDP growth rate over the 1947 to 2021 period.[163] While this supports the view that utility EPS growth can exceed nominal GDP growth, the Commission notes that D. Madsen provided evidence of the recent historical EPS growth rates of the Alberta utilities and concluded that average growth was generally lower than his forecast nominal GDP.[164] Further, he noted that the Alberta utilities have a "natural barrier to growth" due to their inability to expand into other jurisdictions.[165] On this point, the Commission notes that growth in dividends can come from higher earnings, and not only from the expansion of company operations.

152. Nevertheless, as in past decisions, the Commission remains concerned with the aggressive dividend growth rates and forecasts relied on by some experts for the utilities, both for utilities as a sector of the economy, and the economy as a whole. It notes Dr. Cleary's observation regarding high growth estimates put forward by experts for the utilities and for the economy as a whole:

158 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 41; Exhibit 27084-X0471, Villadsen evidence, PDF page 12; Exhibit 27084-X0315, Concentric evidence, PDF page 54; Exhibit 27084-X0292, Madsen evidence, PDF page 32; Exhibit 27084-X0304, Madsen evidence, Sheet DCF.

159 Exhibit 27084-X0320.02, Cleary evidence PDF pages 65-69; Exhibit 27084-X0334.01, Sheet 1.

160 Exhibit 27084-X0391, D'Ascendis evidence, Sheets 2.2-2.4 CGDCF. EPS estimates were from Value Line, Zack's, and Yahoo! Finance; Exhibit 27084-X0469.01, Villadsen evidence, PDF page 51; Exhibit 27084-X0315, Concentric evidence, PDF page 54.

161 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 64-65.

162 Exhibit 27084-X0315, Appendix 1, Evidence of Concentric Energy Advisors, PDF pages 56-57.

163 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 159, Schedule 3, and Exhibit 27084-X0665.

164 Exhibit 27084-X0292, Madsen evidence, PDF page 38.

165 Exhibit 27084-X0292, Madsen evidence, PDF page 38.

> The contradiction in these assumptions is obvious – i.e. if the economic environments are expected to experience high-risk and slow growth conditions, how is it reasonable to assume that corporate earnings and dividends (for the entire stock market of all publicly listed companies) can be expected to grow indefinitely at these abnormally high rates?[166]

153. In the 2018 GCOC decision, with reference to Dr. Cleary's evidence, the Commission recognized that the utilities are essentially monopolies in mature markets and, because of this, the use of long-term growth in excess of the long-term growth of GDP is unreasonable.[167] Indeed, D. Madsen quoted in his evidence from a publication by Dr. Damodaran, who opined that it is questionable whether any firm is able to sustain high growth in the long term as it will eventually stop growing either due to limitations on size or to the effects of competition.[168]

154. On the other hand, the sustainable growth rate Dr. Cleary used to estimate expected dividend growth rates relied on historical seven-year average dividend yields and payout ratios and used accounting data, rather than readily available, market-driven forecasts. The Commission notes that this approach produces growth estimates that are less than actual historical rates of dividend growth[169] and less than inflation, resulting in negative real growth. As a result, the Commission is concerned that Dr. Cleary's sustainable growth rate produces results that understate dividend growth.

155. The Commission will generally continue to consider forecast long-term nominal GDP growth as a proxy for forecast dividend growth. Growth of the utilities will fluctuate over the years but, overall, considering the business profile of the utilities, the Commission does not expect the utilities will consistently achieve growth in dividends greater than the nominal GDP growth rate.

156. In this regard, the Commission finds it reasonable to use in the constant growth DCF model the minimum and mean analyst growth rates submitted in this proceeding; however, maximum EPS growth rates appear to be unreasonably high. Despite its general criticism of using high dividend growth rates, the Commission notes that analyst EPS growth estimates are widely used by the investment community, and concerns relating to analyst EPS optimism bias for large capitalization stocks like those in the comparator group may be overstated, at least relative to estimates for small to mid-cap stocks of which there are not many in the comparator group, in any event.[170] The use of analyst EPS estimates supplied by established data service providers, such as Value Line, Zack's, Yahoo! Finance, SNL Financial, and Thomson First Call minimizes the opportunity for arbitrary adjustments and custom calculations for which there is no broad support among parties to the proceeding.

6.4.3 Multi-stage DCF model

157. The multi-stage DCF model reflects the premise that investors value an investment according to the present value of its expected cash flows over time.[171] It is an extension of the constant growth DCF model, but the multi-stage DCF approach does not assume a single,

166 Exhibit 27084-X0759, Dr. Cleary rebuttal evidence (redacted), PDF page 3.
167 Decision 22570-D01-2018, paragraph 438.
168 Exhibit 27084-X0292, D. Madsen evidence, PDF pages 34-35.
169 Exhibit 27084-X0304, Madsen evidence, Tab DCF, column "Growth forecast past 5 years (per annum)."
170 Transcript, Volume 3, pages 704-722.
171 Exhibit 27084-X0390, Concentric evidence, PDF page 53.

constant estimate of dividend growth in perpetuity.[172] In general, the multi-stage DCF assumes that dividends grow at a constant rate over a short-term period, usually five years in length, transition to an assumed long-term constant growth rate over an interim period, also usually five years in length, and then grow in perpetuity at a growth rate usually equal to forecast nominal GDP.

158. The multi-stage DCF recommendations of parties are summarized in the following table.

Table 5. Multi-stage DCF recommendations of parties

Witness (sponsoring party)	ROE	Flotation allowance	ROE including flotation allowance
		(%)	
D. D'Ascendis (AltaLink/EPCOR)[173]	10.34 (Canadian utilities) 9.21 (U.S. electric utilities) 9.39 (U.S. natural gas)	0.50	10.84 (Canadian utilities) 9.71 (U.S. electric utilities) 9.89 (U.S. natural gas)
Dr. Villadsen ATCO/Apex/Fortis)[174]	11.81 (Canadian utilities) 7.88 (U.S. electric utilities) 7.62 (U.S. gas utilities)	0.50	12.31 (Canadian utilities) 8.38 (U.S. electric utilities) 8.12 (U.S. gas utilities)
Concentric (ENMAX)[175]	9.42 (Canadian proxy group) 8.28 (U.S. electric proxy group) 8.65 (U.S. Gas proxy group) 8.49 (N.A. combined proxy group)	0.50	9.92 (Canadian proxy group) 8.78 (U.S. electric proxy group) 9.15 (U.S. gas proxy group) 8.99 (N.A. combined proxy group)
Dr. Cleary (UCA)[176]	7.01	0.50	7.51
D. Madsen (IPCAA)[177]	7.38-8.46	0.50	7.88-8.96

6.4.3.1 Multi-stage DCF inputs

159. The variables that must be estimated in a multi-stage DCF equation are the same as those set out in Section 6.4.2, except the assumed short-term and long-term dividend growth rates and the length of the short-term and transition periods are expressed in years.

Dividend growth rate

160. Most of the experts calculated the multi-stage DCF in a similar manner, and many of the variables are calculated in the same way as for the constant growth DCF calculations, other than the dividend growth rate. As was the case for the constant growth DCF model, parties took different approaches to forecasting the growth rate.[178] In forecasting nominal GDP growth rates, parties used either the Canadian forecast, or a combination of the Canadian and U.S. forecast.

172 Exhibit 27084-X0390, Concentric evidence, PDF page 53.
173 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 50. Recommended M-DCF reflects average of mean and median results.
174 Exhibit 27084-X0469.02, Villadsen evidence, PDF pages 54-55. ROE values are presented at 40% equity thickness.
175 Exhibit 27084-X0315, Concentric evidence, PDF page 59. Exhibit 27084-X0490, tab "JMC-4 Multi-Stage DCF."
176 Exhibit 27084-X0320.02, Cleary evidence, PDF pages 70-71.
177 Exhibit 27084-X0292, Madsen evidence, PDF pages 29-44. Exhibit 27084-X0304, Madsen evidence, Sheet DCF.
178 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 47-48. Exhibit 27084-X0391, D'Ascendis evidence, sheets 2.5-2.8, Exhibit 27084-X0469, Villadsen evidence, PDF pages 49-57. Exhibit 27084-X0471, Villadsen evidence, PDF pages 10-13, Exhibit 27084-X0315, Concentric evidence, PDF pages 57-58. Exhibit 27084-X0490, Sheet JMC-4 Multi-Stage DCF.

161. D. Madsen also calculated the multi-stage DCF using the approach used by the U.S. Federal Energy Regulatory Commission (FERC), applying it to several scenarios.[179] Using the FERC approach led to similar growth rates. Dr. Cleary took a slightly different approach and used a variation of the constant growth DCF called the H-Model. The approach assumes that growth in dividends moves in a linear manner from a short-term growth rate toward a long-term growth rate over a specified period of time, defined as the “half life.”

162. D. Madsen’s multi-stage DCF calculations included using current and one-year forecast EPS growth rates as a proxy for a five-year forecast EPS growth rate or a one-year EPS growth estimate in year one and the five-year EPS estimate in years two to five.[180] D. Madsen also used the FERC two-step DCF approach. He made adjustments to the FERC approach, including the weights used for short- and long-term growth, and used a simple average of the short-term and long-term growth estimates to adjust the dividend. These adjustments were criticized by Dr. Villadsen and D. D’Ascendis.[181]

163. The multi-stage DCF approach used by Dr. Villadsen[182] models the first five years of dividends at a growth rate specific to the company she is estimating, then tapered the growth down towards that of the economy over the next five years. For year 10 onwards, Dr. Villadsen used the GDP growth rate as the perpetual growth rate for dividends.

164. Regarding the results of Dr. Cleary’s H-Model DCF approach, the Commission is persuaded by the concerns expressed by experts for the utilities who raised a number of empirical and qualitative issues with Dr. Cleary’s approach. These included the use of sustainable growth rates that are less than forecast inflation,[183] resulting in negative real utility growth, sustainable growth rates that are less than historical actuals,[184] and the need to consider growth arising from both internally generated funds and from issuances of equity.[185]

6.4.4 Other risk premium models

165. In addition to relying on CAPM and DCF models, some parties used the following risk premium models to help inform their fair ROE estimates: (i) Concentric and Dr. Villadsen used the government bond yield risk premium model; (ii) Dr. Cleary and D. D’Ascendis relied on the utility bond risk yield premium model; and (iii) D. D’Ascendis used the predictive risk premium model. The Commission determines that it will not rely on any of these models for the purposes of the present decision.

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179 Exhibit 27084-X0292, Madsen evidence, PDF pages 42-44. Exhibit 27084-X0304, Madsen evidence.

180 Exhibit 27084-X0304, Madsen evidence, Sheets DCF and Multi DCF Alt. FERC Scenario 1: nominal estimated GDP of 3.77% is used for both the short-term and long-term growth rate; FERC Scenario 2: short-term growth rate is the average of the current year forecast and next year’s growth rate and nominal estimated GDP of 3.77% is used as the long-term growth rate; FERC Scenario 3: short-term growth rate is equal to analyst five-year EPS growth rates and nominal estimated GDP of 3.77% is used as the long-term growth rate; and FERC Scenario 4: the average the short-term growth rate in scenarios 1 to 3 is used as the short-term growth rate and the long-term growth rate is nominal estimated GDP of 3.77%.

181 Exhibit 27084-X0761, Villadsen evidence, PDF pages 26-27, Exhibit 27084-X0750, D’Ascendis evidence, PDF pages 32-36.

182 Exhibit 27084-X0471, Villadsen evidence, PDF pages 9-10.

183 Exhibit 27084-X0750, D’Ascendis evidence, PDF page 29.

184 Exhibit 27084-X0743, Concentric evidence, PDF page 41.

185 Exhibit 27084-X0761.02, Villadsen evidence, PDF page 61.

166. The government bond risk premium approach estimates the ROE as the sum of the ERP and the yield on the 30-year U.S. Treasury bond. The ERP was calculated as the difference between authorized returns from U.S. electric and gas utilities and the then-prevailing quarterly 30-year U.S. Treasury yield. Consistent with prior GCOC decisions,[186] the Commission continues to be of the view that the approved ROEs from other jurisdictions are not, strictly speaking, wholly market-based data and therefore, will not place any weight on the results of the government bond risk premium model.

167. Under the utility bond risk premium approach, a required ROE is calculated by adding an equity premium to a utility bond yield. In past GCOC decisions, the Commission accepted the bond yield and utility bond yield approaches to be valid tools in estimating the cost of equity, as they are simple to use and conform to the basic principle that investors require a higher return for assets with greater risk. Although the Commission still considers the empirical basis of the utility bond yield methodology to be valid, for the purposes of this decision the Commission will not rely on the utility bond yield risk premium approaches used by Dr. Cleary and D. D'Ascendis.

168. Dr. Cleary's recommended risk premium of 2.50 per cent is subjective, not supported by any analysis and does not take into the account the changing market environment. D. D'Ascendis's risk premiums are estimated in a more rigorous manner; however, they have issues of their own. For one of his models, D. D'Ascendis used the authorized ROEs from litigated cases in other jurisdictions to estimate the utility bond ERP.[187] As stated earlier, the Commission prefers not to use authorized ROEs as a proxy for market data. For the other two models, D. D'Ascendis relied on market data; however, they require the Commission's determinations on a number of new variables such as the expected utility bond yields and expected returns for an index of U.S. utilities.[188] Variables and calculations in D. D'Ascendis's bond yield risk premium models were not explored in depth in this proceeding, and in the Commission's view, the merits of the utility bond risk premium approach do not outweigh the additional burden and empirical difficulties associated with measuring the ERP to utility bond yield, given the presence of the more widely accepted CAPM and DCF models.

169. Finally, the predictive risk premium model is based on the ARCH/GARCH[189] models that use historical volatility to predict future volatility, which can then be translated to a predicted ERP. The predictive risk premium model estimates the ERP directly, by predicting volatility or risk.[190] In the Commission's view, this analysis is similar in concept to the technical analysis of market data that relies only on historical time series data for a single indicator, for example, returns on a stock, to predict future returns for this stock. The Commission is not persuaded that this approach is superior to the CAPM and DCF models that use a variety of inputs to estimate the ERP and/or required return, especially as the predictive risk premium model approach is not used widely, if at all, by other regulators.

186 Decision 22570-D01-2018, PDF pages 88-91.
187 Exhibit 27084-X0390, D'Ascendis evidence, PDF page 64.
188 In Exhibit 27084-X0390, PDF page 63, D'Ascendis explained, "As done for the S&P TSX Composite and the S&P 500, using dividend and EPS growth rate data from Bloomberg, I calculated projected total returns of the S&P/TSX Capped Utilities."
189 The Autoregressive Conditional Heteroskedasticity (ARCH) and Generalized Autoregressive Conditional Heteroskedasticity (GARCH) models are based on the premise that the volatility of prices and returns clusters over time and is therefore highly predictable.
190 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 54-60.

6.4.5 Notional ROE and base forecast ERP

170. In this proceeding, the Commission was presented with a wide range of notional ROE and base ERP recommendations that were based on a variety of approaches, models and directional indices. The Commission rejected many of these approaches and instead focused on the results of the well-known and widely used models (CAPM, constant growth DCF, and multi-stage DCF) in GCOC proceedings. The Commission determines the notional ROE to be 9.00 per cent and the base forecast ERP to be 5.90 per cent.

171. Table 6 illustrates the ranges of notional ROE (including 0.50 flotation allowance) based on the results of the financial models submitted by the parties and reflects the resulting ERPs after subtracting the Commission's 3.10 per cent risk-free rate.

Table 6. Notional ROE and base forecast ERP from financial models

Financial model	ROE (%) range		Base forecast ERPs (%) range including flotation allowance (ROE less 3.10% risk-free rate)	
	Low	High	Low	High
CAPM	5.7	11.76	2.6	8.66
Constant growth DCF	6.85	13.29	3.75	10.19
Multi-stage DCF	7.51	12.31	4.41	9.21

172. It is obvious from the table above that the Commission was presented with a wide range of results from the experts using the CAPM, constant growth DCF, and multi-stage DCF models. The model results are subject to a high degree of variability given the range of data sources, forecasts and assumptions that parties choose to use, and the judgment and experience of the expert doing the modelling. These models provide some guidance to the Commission, but, as evidenced by the wide range of results, they do not produce a single correct number for the fair return that the Commission should choose.

173. In assessing the results of the models, the Commission is mindful of its concerns expressed in sections 6.4.1 to 6.4.3, including:

- CAPM results using a forecast risk-free rate that differs significantly from the 3.10 per cent rate the Commission found reasonable in Section 6.3.
- CAPM results using betas that were close to or exceeded one.
- CAPM results using MERPs based on excessively high earnings growth rates in estimating market return.
- Constant growth DCF results using dividend growth rates that are too high (e.g., exceed long-term nominal GDP growth) or too low (e.g., near or less than inflation).

174. The Commission has set the base forecast ERP and resulting notional ROE towards the lower end of the ROE ranges calculated in the financial models given its finding that the risk profile of the Alberta utilities is at the low end of the comparator group of companies.

175. D. D'Ascendis calculated a low CAPM ROE of 8.38 per cent, a constant growth DCF ROE of 9.84 to 10.71 per cent and a multi-stage DCF ROE of 9.71 to 10.84 per cent. Some of D. D'Ascendis's DCF ROE estimates are based on excessively high earnings growth rates, which

the Commission rejects. The notional ROE of 9.00 per cent is closer to the lower end of D. D'Ascendis's three calculations, namely the low 8.38 per cent CAPM ROE.

176. The low end of Dr. Villadsen's calculated ROEs was the 8.12 per cent for the multi-stage DCF. Dr. Villadsen's CAPM ROE of 9.81 to 11.76 per cent uses a high beta and high risk-free rate. Concentric's CAPM ROE of 10.73 uses a lower beta and risk-free rate than Dr. Villadsen; however, Concentric's risk-free rate is 3.73 per cent. The low end of Concentric's calculated ROEs is 8.78 per cent for the multi-stage DCF. Dr. Villadsen and Concentric's constant growth DCF ROEs range from 9.88 to 13.29 per cent, and 9.93 to 10.38 per cent, respectively. Some of Concentric's constant growth DCF estimates are based on excessively high earnings growth rates, which the Commission rejects.

177. The high end of Dr. Cleary's three ROE calculations was 7.51 per cent for the multi-stage DCF but even that high-end estimate is too low. It is approximately 100 basis points lower than the current approved ROE, and the Commission finds no compelling reason to decrease the currently approved ROE. D. Madsen calculated a CAPM ROE of 7.51 per cent, a constant growth DCF ROE range of 7.81 per cent to 9.64 per cent, and a multi-stage DCF ROE range of 7.88 per cent to 8.96 per cent. Given the Commission's finding that there is no compelling reason to decrease the currently approved ROE, the Commission considers the higher end of D. Madsen's constant growth DCF and multi-stage DCF ROEs to be more helpful. D. Madsen uses long-term nominal GDP growth rates in his DCF models. The notional ROE of 9.00 per cent is lower than D. Madsen's 9.64 per cent constant growth DCF ROE, and slightly higher than D. Madsen's 8.96 per cent multi-stage DCF ROE.

178. In addition to the various factors outlined above, the Commission's reasoning in setting the base forecast ROE and notional ROE on the lower end of the ROE ranges developed by parties in this proceeding includes the considerations set out below.

179. A great deal of evidence (and supporting argument) was filed in this proceeding by the utilities in an effort to persuade the Commission that the macroeconomic changes (and related systematic risks) confronting them compared to what they faced in 2018, together with other business, market, regulatory, competitive and related operating risks they deal with on a daily basis, warrant a significant increase in both their approved ROEs and deemed equity ratios commencing in 2024. After considering the full record of this proceeding, the Commission finds that, on balance, there are reasonable grounds for the notional ROE for Alberta utilities to be raised above the 8.5 per cent ROE approved for 2023, but not to set it as high as the utilities have been requesting.

180. Utilities are regulated monopolies. They supply essential, highly price-inelastic, services to captive customers, with few, if any, competitively available substitutes. Aside from fluctuations attributable to short-term extremes of weather, natural disasters, pandemics and the like, demand for their services is highly predictable from one season to the next, and one year to another.

181. In exchange for being cloaked with a legislative "duty to serve" or "supplier-of-last-resort" obligation as it is sometimes called, public utilities have long been the beneficiaries of a statutory guarantee, enforced by regulation and a century or more of appellate level jurisprudence, of a legal right to a reasonable opportunity to earn a fair return on their prudently invested capital. As leading credit rating agencies have noted on more than one occasion, utilities

under the Commission's jurisdiction face a favourable regulatory environment that excludes some or all of volumetric, counterparty and commodity price risks,[191] and allows for the flowthrough to customers of most, if not all, cost increases that are outside the utility's direct control.

182. Alberta utilities are also the beneficiaries of a concerted effort in recent years to eliminate regulatory lag and to reduce unnecessary regulatory burden, plus numerous incentives to cut costs and earn supra-normal returns (i.e., earnings in excess of their approved rate of return) between rate cases under cost-of-service (COS) regulation for transmission utilities or performance-based regulation (PBR) terms for distribution utilities.[192] Together, these conditions have the effect of significantly reducing the overall level of risk faced by Alberta utilities relative to the market as a whole. As noted in Section 4 above, while many competitive industries endured considerable economic and financial duress attributable to pandemic-related disruptions in the past few years, Alberta utilities appear not only to have avoided any lasting economic harm but have also exhibited, overall, very robust financial results throughout. Moreover, the fact that no evidence was presented by utilities attesting to undue hardship in raising new debt or equity capital on competitive terms at any time since the 2018 GCOC proceeding reinforces the overall conclusion that they operate in a lower risk and relatively more supportive regulatory environment than that of the comparator group.

6.5 Other variables of the formulaic approach

183. The approved notional ROE of 9.0 per cent will serve as a base ROE to which the approved formulaic approach will be applied each year:

$$ROE_t = 9.0\% + 0.5 \times (\mathrm{YLD}_t - 3.10\%) + 0.5 \times (\mathrm{SPRD}_t - \mathrm{SPRD}_{base})$$

184. This section explains how the Commission arrived at each remaining variable to be used in the approved formulaic approach. Specifically, Section 6.5.1 deals with the adjustment factors for changes in GoC bond yield and utility bond yield spread. Section 6.5.2 deals with the base and test year values for long GoC bond yields. Section 6.5.3 deals with the base and test year values for utility bond yield spreads.

6.5.1 Adjustment factors for changes in GoC bond yield and utility bond yield spread

185. In future test years, risk-free rates (approximated by long-term GoC bond yield) and utility bond yield spreads will continue to vary as financial and economic conditions evolve. The approved formulaic approach accounts for fluctuations in both of these factors relative to their base values approved in this decision.

186. The adjustment factor for the 30-year GoC bond yield (denoted as w_1 in the formula) expresses the relationship between changes in the forecast long GoC bond yield and the ROE for the test year. The adjustment factor for utility bond yield spread (denoted as w_2 in the formula) expresses the relationship between changes in the utility bond yield spread and the ROE for the test year. The theoretical basis behind these adjustment factors is that the ROE (and underlying

191 Exhibit 27084-X0897, IPCAA-ATC-4, Extract from Proceeding 28174, Exhibit 28174-X0011, SP Rating Results for AltaLink, L.P., PDF pages 4 and 6.

192 The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR. Notwithstanding that, the Commission observes that some Alberta utilities under COS regulation do achieve returns over approved ROE.

ERP) do not change one-for-one with the change in risk-free rate and bond yield spread; rather, they change to some lesser degree in response to fluctuations in those variables.

187. Ideally, the values for these adjustment factors should be determined through an empirical exercise based on the strength of the relationship between interest rates and ERPs observed by analysing historical data. To that effect, the Commission asked parties to comment on the extent of the relationship between changes in the forecast long GoC bond yield and the forecast ERP, and whether this relationship is sustainable and statistically significant with a high coefficient of determination.

188. In the Commission's view, the results of the statistical analyses presented in this proceeding were not conclusive. Although there were some statistical analyses showing that the 0.5 adjustment factors for both w_1 and w_2 were in the range of reasonableness,[193] with the exception of Concentric, parties did not rely heavily on their statistical analyses and, instead, appeared to defer to the OEB adjustment factors of 0.5 for both w_1 and w_2, the latter of which is also used by the California Public Utilities Commission (CPUC). This was the approach taken by Dr. Villadsen,[194] D. D'Ascendis[195] and D. Madsen.[196]

189. Concentric's regressions showed a statistically significant, sustained relationship between changes in risk-free rates and authorized ROEs as well as between changes in utility bond yield spreads and authorized ROEs.[197] Based on these regressions, Concentric recommended the 0.5 adjustment for both factors in the formula.[198] However, the Commission will not rely on this analysis given its determination, expressed throughout this decision, not to use authorized ROEs as a proxy for market data.

190. An alternative to the adjustment factors used by the OEB was presented by Dr. Cleary who recommended adjustment factors of 0.75 for both w_1 and w_2. The Commission is not persuaded that a 0.75 adjustment factor is warranted. Although of limited usefulness, the statistical analyses on the record of this proceeding (not including Concentric's) do provide general support for the 0.5 adjustment factors; at least more so than for the 0.75 adjustment factor. In addition, both the OEB and the EUB found that the 0.75 adjustment factor with respect to changes in GoC bond yield resulted in unduly heightened sensitivity to GoC bond yield, contributing to the demise of their formulas that were in place pre-2009.[199] The Commission agrees with the approach taken by the majority of parties that it is preferable to use the adjustment factors used by the OEB and CPUC whose formulas have been in place for a number of years.

193 Exhibit 27084-X0900, Madsen undertaking No. 1. D'Ascendis: Exhibit 27084-X0399, Morin approach; Exhibit 27084-X0408, Harris approach; Exhibit 27084-X0411, Harris and Marston approach; Exhibit 27084-X0413, Brigham, Shome and Vinson approach; Exhibit 27084-X0440, Maddox, Pippert and Sullivan approach. Dr. Cleary: Exhibit 27084-X0605, UCA-AUC-2023FEB21-005, PDF pages 14-15.

194 Exhibit 27084-X0469, Villadsen evidence, PDF page 79.

195 Exhibit 27084-X0390, D'Ascendis evidence, PDF pages 105, 112.

196 Exhibit 27084-X0292, Madsen evidence, PDF page 50.

197 Exhibit 27084-X0490, tabs "JMC-7.1 Risk Premium – Electric" and "JMC-7.2 Risk Premium – Gas."

198 Exhibit 27084-X0315, Concentric evidence, PDF page 109. Exhibit 27084-X0743, Concentric reply evidence, PDF page 51.

199 Exhibit 27084_X0678, EDTI-AML-CCA-2023FEB21-003 Attachment (OEB Report), PDF page 3.

191. The Commission approves a 0.5 adjustment factor for both changes in the 30-year GoC bond yield (w_1) and changes in the utility bond yield spread (w_2) in the formula.

6.5.2 Base and test year values for long-term GoC bond yield

192. As set out in Section 6.3, the risk-free rate of 3.10 per cent will serve as the base long-term GoC bond yield (YLD_{base}) in the formulaic approach. The updated risk-free rate forecast for each test year will be measured against this base value.

193. Regarding the 30-year GoC bond yield forecast for the prospective test year (YLD_t), parties recommended that methodologies be employed consistent with the methods they used to arrive at their respective base risk-free rate estimates (these methodologies are summarized in Table 1 from Section 6.3). Parties' choice of which forecast publication date to use was based on their assumptions as to when the Commission will calculate the ROE for the upcoming test year; on that basis parties presumed the Commission will rely on either September or October data.

194. The Commission agrees with parties that it is beneficial to maintain consistency in forecasting methods between base and test year values and therefore will use the same method for forecasting the risk-free rate. In Section 6.3, the Commission determined that it will base the calculations for a test year on the data from October of the preceding year. Consistent with these determinations, the Commission finds that forecast long-term GoC bond yield will be calculated as the weighted average of (i) the 30-year GoC bond yield forecasts published by RBC, TD and Scotiabank in October, or the most recent month prior to October, preceding the test year for the forecast period spanning from Q1 to Q4 of the test year (0.75 weight); and (ii) the naïve forecast representing the average long-term GoC bond yield[200] over the period October 1 to October 31 each year preceding the test year (0.25 weight).

6.5.3 Base and test year values for utility bond yield spread

195. In general terms, the utility bond yield spread is calculated as a difference between the utility bond yield and GoC bond yield of the same maturity.

196. Consistent with her recommendations to use the 30-year GoC bond yield for the forecast risk-free rate, Dr. Villadsen recommended calculating the spread against the yield on 30-year utility bonds. Dr. Villadsen also advised that the utility bond yield spread should be estimated using a bond index that measures the market-based yields on a broad portfolio of Canadian utility bonds. She recommended the 30-year A-rated Canadian Utility Bond Index from Bloomberg (Series C29530Y) for this purpose. The spread can then be calculated as the current yield on 30-year A-rated Canadian utility bonds minus the current yield on the 30-year GoC bond, as of the same valuation date that the other "base" inputs are established in the formula. Dr. Villadsen stated the Commission may consider using the average yield over a historical period (e.g., the prior 15 days) to account for any potential one-day pricing effects.[201] In her evidence, Dr. Villadsen noted that the base spread at the end of November 2022 was 1.63 per cent.[202]

197. Other parties generally followed the same methodology as Dr. Villadsen for calculating the base utility bond yield spread, but differed in certain aspects. In Concentric's view, the utility

[200] Bank of Canada CANSIM Series V39056.
[201] Exhibit 27084-X0469.01, PDF page 82.
[202] Exhibit 27084-X0469.01, PDF page 33 at Figure 6, PDF page 80.

bond yield spread should consider both A-rated and Baa-rated utility bonds because not all of the Alberta utilities have an A rating. Further, Concentric suggested that if the A and Baa-rated bond yield spreads differ, the Commission could average them or differentiate the resulting ROE separately for the A and sub-A rated utilities. Concentric stated that the base utility bond spread should be calculated based on market data at the end of December 2022.[203] D. D'Ascendis recommended setting the base spread using the average utility bond yield spread for the month of December 2022 in the amount of 1.64 per cent.[204] Dr. Cleary recommended using the actual, prevailing A-rated 30-year utility bond yield spread at the time the base ROE is set. For example, Dr. Cleary observed that the 30-year GoC bond yield of 2.85 per cent as of January 19, 2023, implied an A-rated utility yield spread of 1.58 per cent versus the spread of 1.31 per cent as of January 2020, and the average spread of 1.39 per cent over the January 3, 2003, to January 19, 2023 period.[205]

198. Regarding the utility bond yield spread for the upcoming test year, parties preferred to use the same methodologies they recommended for calculating the base value of the spread. The only difference was to use data from either September or October, i.e., at the same time the Commission computes the other parameters of the formulaic approach.

199. The Commission agrees with the mechanics of the utility bond yield spread calculations as described by Dr. Villadsen and used by most parties. The Commission also agrees with the selection of the 30-year A-rated Canadian Utility Bond Index from Bloomberg given the Commission's continued recognition of the importance of maintaining a target credit rating for the Alberta utilities in the A-range, as discussed in Section 7.3. As well, the Commission agrees with Dr. Villadsen that the base utility bond yield spread should be set based on data from the same time period that is used to establish the other "base" inputs in the formula. Therefore, the Commission will use the average utility bond yield spread for the month of February 2023 for the base value in the formula to be consistent with the time period selected for the data used to set the risk-free rate in Section 6.3.

200. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula.

201. Regarding the utility bond yield spread for the test year ($SPRD_t$), as was recommended by the majority of parties, the Commission will calculate the average difference between (i) the 30-year A-rated Canadian utility bond yield[206] and (ii) the long-term GoC bond yield[207] over the period October 1 to October 31 of the year preceding the test year.

203 Exhibit 27084-X0315, PDF page 111.
204 Exhibit 27084-X0390, PDF page 9.
205 Exhibit 27094-X0320.02, PDF page 20.
206 Bloomberg Series C29530Y.
207 Bank of Canada CANSIM Series V39056.

7 Capital structure

7.1 Overview, approved deemed equity ratios for 2024, and review timeframe

202. To satisfy the fair return standard, the Commission is required to determine a fair return on the deemed equity component of invested capital. In this section, the Commission will determine the deemed equity ratios (also referred to as capital structure) – that is, the approved deemed portion (percentage) of rate base, net of no-cost capital, supported by common equity, for each of the utilities.

203. In this decision, the Commission maintains its previous approach of setting a uniform approved ROE, and then adjusting for any differences in risk among each of the utilities by adjusting the deemed equity ratios. The Commission will make adjustments, if required, to recognize changes in relative risk for each utility from the deemed equity ratios approved for 2023 in Decision 27084-D01-2022.

204. The Commission finds that no change is required to the deemed equity ratios set out in the 2018 GCOC decision. The Commission has determined that a deemed equity ratio of 37 per cent for both distribution and transmission utilities (with the exception of Apex, whose deemed equity ratio will remain at 39 per cent), including those which pay income tax and those which currently are income tax exempt or do not currently pay income tax, satisfies the fair return standard when combined with a 9.0 per cent approved notional ROE, and will enable the utilities to target a credit rating in the A-range.

205. The Commission considers that the deemed equity ratios should be reviewed every five years, or whenever the ROE formula is reviewed, whichever happens first, and finds that this promotes regulatory efficiency. In the case of any material changes in business risk that occur before the scheduled review of the deemed equity ratios approved in this decision, parties can request that the Commission undertake an earlier review as further described in Section 5.5.

206. The section is organized as follows. In Section 7.2, the Commission briefly outlines the deemed equity ratios recommended by the parties. In Section 7.3, the Commission addresses the targeting of credit ratings in the A-range. In Section 7.4, the Commission discusses credit metrics required by a typical pure-play regulated utility in Canada in order to achieve an A-range credit rating. The Commission also evaluates the credit metrics of the utilities having regard to significant financial parameters observed in Rule 005 filings and other evidence on the record of this proceeding, including the embedded average debt rate, depreciation as a percentage of invested capital, the income tax rate and the mid-year construction work in progress (CWIP) as a percentage of invested capital.

207. The Commission's consideration of the other factors relevant to the determination of an approved deemed equity ratio for each utility is in Section 7.5 with a review of the evidence in relation to changes in business risk that impact all the utilities. The Commission addresses the submissions of Fortis and Apex regarding their deemed equity ratios in Section 7.6.

7.2 Requested deemed equity ratios

208. The currently approved deemed equity ratios and the ratios recommended by parties for 2024 are set out in the following table.

Table 7. Currently approved deemed equity ratios and the deemed equity ratios recommended for 2024

	Last approved[208]	Recommended by Apex/ATCO Utilities/Fortis[209] Dr. Villadsen	Recommended by AltaLink/ EPCOR[210] D. D'Ascendis	Recommended by ENMAX[211] J. Coyne	Recommended by IPCAA[212] D. Madsen	Recommended by the UCA[213] Dr. Cleary
Electricity and natural gas transmission						
AltaLink	37		40		35	37
ATCO Electric Transmission	37	42			35	37
ATCO Pipelines	37	40				37
ENMAX Transmission	37			40	35	37
EPCOR Transmission	37		40		35	37
KainaiLink L.P.	37					
Lethbridge	37					
PiikaniLink L.P.	37					
Red Deer	37					
TransAlta	37					
Electricity and natural gas distribution						
Apex	39	44				39
ATCO Electric Distribution	37	40			35	37
ATCO Gas	37	40				37
ENMAX Distribution	37			40	35	37
EPCOR Distribution	37		40		35	37
Fortis	37	43			35	37

209. Dr. Villadsen conducted a credit ratio analysis to determine at what approved ROE and equity ratio combination the ATCO Utilities, Fortis and Apex would meet standard credit metric benchmarks from credit rating agencies such as the earnings before interest and taxes (EBIT) coverage, funds from operations (FFO) coverage, and FFO to debt metric. She also looked at DBRS and Moody's stated debt to rate base benchmarks in recommending a deemed equity percentage of about 40 per cent for ATCO Electric Distribution, ATCO Gas, ATCO Pipelines, and Fortis. She noted that F. Graves further recommended an "about 300 [bps] of equity percentage" increase in the equity ratio of Fortis, and Dr. Villadsen adopted that recommendation. Dr. Villadsen noted that at a 10 per cent ROE, ATCO Electric Transmission only met the FFO coverage and FFO to debt metric at about 42.5 per cent equity, so she recommended a deemed equity ratio of about 42 per cent equity for ATCO Electric Transmission.

208 Decision 27084-D01-2022, paragraph 59.

209 Exhibit 27084-X0469.01, PDF pages 104-105. Dr. Villadsen concurred with M. Tolleth that the deemed equity ratio for Apex be at least 400 basis points higher than the other utilities. Exhibit 27084-X0921, PDF page 2. Exhibit 27084-X0925, PDF page 17. Exhibit 27084-X0930, PDF page 20.

210 Exhibit 27084-X0390, PDF page 133. Exhibit 27084-X0928, PDF page 32.

211 Exhibit 27084-X0315, PDF page 19. Exhibit 27084-X0924, PDF page 32.

212 Exhibit 27084-X0292, PDF page 6. Exhibit 27084-X0918, PDF page 31.

213 Exhibit 27084-X0320.02, PDF page 6. Exhibit 27084-X0926, PDF page 34.

For Apex, Dr. Villadsen recommended an equity percentage at least 400 basis points higher than the benchmark based on the business risk analysis by M. Tolleth.[214]

210. Dr. Villadsen benchmarked her recommended deemed equity ratios against deemed equity ratios approved by other Canadian regulators, noting that the OEB approved a deemed equity ratio of 40 per cent for electric distributors and 36 to 40 per cent for gas distributors, while the British Columbia Utilities Commission has approved equity ratios of 38.5 per cent or more, and the Régie de l'énergie du Québec has approved equity ratios of between 38.5 and 46 per cent.[215] In the U.S., the average equity ratios in 2021-2022 for electric and gas distribution utilities were 50.2 and 51.1 per cent, respectively.[216]

211. M. Tolleth concluded that in order to satisfy the fair return standard, Apex's deemed equity ratio should be set at a premium to that of the generic benchmark gas distribution utility, in recognition of the higher market cost of capital associated with its small size and correspondingly elevated risk. He further concluded that based on fundamental finance principles and market evidence, any partially countervailing reduction to Apex's deemed equity ratio for purposes of "balancing" the higher market cost of debt experienced by small utilities such as Apex would not be consistent with the fair return standard. M. Tolleth submitted that it would be appropriate for the Commission to set Apex's deemed equity ratio at least 400 basis points (bps) above that of the "generic" Alberta gas distribution utility.[217]

212. F. Graves submitted that it is clear that the REA issue faced by Fortis presents a material financial risk, and can be offset by either allowing an ROE increase of 68 bps for Fortis, or an increase of about 300 bps in the deemed equity ratio of Fortis.[218]

213. D. D'Ascendis recommended that the deemed equity ratio applicable to AltaLink and EPCOR should be 40 per cent, which he submitted reflects the substantial increase in market risk since the 2018 GCOC proceeding, and increased business risk faced by AltaLink and EPCOR over that same period.[219] D. D'Ascendis submitted that his 40 per cent recommendation is reasonable when viewed in light of the OEB's approved deemed equity ratio in its annual formula ROE.[220]

214. J. Coyne stated that his assessment showed that while Alberta regulated utilities generally have comparable business risk to companies in the North American proxy group, they have much higher financial risk. He added that the current deemed equity ratio for Alberta utilities is low by Canadian standards and very low when compared to U.S. utilities, and recommended that the Alberta deemed equity ratio be raised to at least 40 per cent. J. Coyne submitted that his recommended 40 per cent deemed equity ratio is the same as that currently allowed for Ontario's electric distribution companies, and equivalent to the Canadian average allowed equity ratio for investor-owned utilities. He commented that a 40 per cent deemed equity ratio is conservative for ENMAX, as it is a non-taxable entity that does not receive the benefit of including income taxes

214 Exhibit 27084-X0469.01, PDF pages 7-8.
215 Exhibit 27084-X0469.01, PDF page 101.
216 Exhibit 27084-X0469.01, PDF page 89.
217 Exhibit 27084-X0377, PDF pages 5-6.
218 Exhibit 27084-X0479, PDF page 47.
219 Exhibit 27084-X0390, PDF page 133.
220 Exhibit 27084-X0390, PDF page 10.

in its revenue requirement, thereby reducing its cash flow metrics as compared to taxable entities.[221]

215. D. Madsen recommended a two per cent reduction to the equity thickness for the electric transmission and electric distribution utilities, from 37 per cent to 35 per cent. He submitted that the business and regulatory risk of the electric utilities has improved since the 2018 GCOC proceeding and that the financial risks and performance of the utilities remains strong. D. Madsen added that the growth rates of the utilities have slowed significantly in recent years which, all else being equal, reduces risk.[222]

216. Dr. Cleary commented that Alberta utilities have low risk as shown by their consistent "low business risk" ratings, low earnings volatility, and most importantly, the ability to generate earned ROEs above the approved ROEs for the last 17 years. Dr. Cleary recommended no change in the approved deemed equity ratios but, rather, emphasized the impetus for a reduction in the approved ROE, based on his belief that it continues to be "well above the actual cost of equity for Alberta utilities." Dr. Cleary submitted that his recommendations are reasonable, and are supported by the credit metric analysis provided by R. Bell.[223]

217. R. Bell noted that if the achieved ROE increases, the level of the deemed equity ratio required to achieve the credit metric targets decreases. He recommended that if the approved ROE increases, the deemed equity ratio be decreased.[224]

7.3 Targeted credit ratings

218. The targeting of credit ratings in the A-range is one of the factors the Commission will continue to use as part of its determination of the deemed equity ratios for 2024 and beyond.

219. Credit ratings assess the credit worthiness of a firm as determined by a credit rating agency. A higher credit rating signals higher confidence in the firm's ability to meet its interest payments and to repay debt principal, allowing the company to borrow at a lower interest rate.

220. Historically, the Commission has recognized the importance of maintaining a target credit rating for the utilities in Alberta in the A-range,[225] and continues to do so. This target credit rating is especially important when interest rates rise. The use of the A-range credit rating target is a factor that respects the financial integrity, capital attraction and comparability aspects of the fair return standard.

221. The Commission finds that, generally, most utilities in Alberta have had little difficulty raising debt and equity financing on satisfactory terms since the 2018 GCOC proceeding, all while maintaining the credit ratings from S&P that were in place during the 2018 GCOC proceeding. The one exception is ENMAX's credit rating, which was decreased largely because of a debt-financed acquisition that was not associated with ENMAX's Alberta operations.[226]

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221 Exhibit 27084-X0315, PDF pages 4-5.
222 Exhibit 27084-X0292, PDF page 62.
223 Exhibit 27084-X0320.02, PDF pages 5-6.
224 Exhibit 27084-X0318, PDF page 20.
225 Decision 22570-D01-2018, PDF page 145, paragraph 689.
226 Exhibit 27084-X0926, PDF page 26, citing Transcript, Volume 2, page 294, line 4 to page 296, line 1.

7.4 Credit metrics

222. Dr. Villadsen,[227] D. D'Ascendis,[228] D. Madsen[229] and Dr. Cleary[230] each took the position that their respective recommended deemed equity ratios either considered credit metrics, or were supported by a credit metric analysis. In past GCOC decisions, the Commission has placed weight on credit metrics.

223. Credit metrics (or financial ratios) are an important, although not the only, component that credit rating agencies consider when assessing the risk of any particular company and assigning a credit rating. As noted in the 2018 GCOC decision, the Commission has historically assessed three principal credit metrics:[231]

- **EBIT coverage:** This is referred to as an interest coverage ratio. In the Commission's credit metric model, it is calculated by grossing up the net income by the statutory income tax rate, adding the return on debt amount, and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate.

- **FFO coverage:** This is also an interest coverage ratio. In the Commission's credit metric model, it is calculated by adding the return on debt amount, the net income and the depreciation collected and dividing the resulting figure by the sum of the return on debt amount and the interest on the CWIP balance, calculated using the deemed debt ratio and the embedded average debt rate. It is important to note that in the Commission's credit model, the interest expense associated with the CWIP balance is not included in the numerator because it is based on the assumption that there is no CWIP included in rate base.

- **FFO/debt:** S&P compares this payback ratio against benchmarks to derive the preliminary cash flow/leverage assessment for a company. S&P notes that this ratio is also useful in determining the relative ranking of the financial risk of companies.[232] In the Commission's credit metric model, it is calculated by adding the net income and the depreciation collected and dividing the resulting figure by the sum of the deemed mid-year debt for rate base and CWIP.

224. In the 2018 GCOC decision, the Commission observed that the credit rating metrics required for an Alberta utility to achieve a credit rating in the A-range had not changed since the 2016 GCOC decision. Those guidelines were EBIT coverage of 2.0, FFO coverage of 2.0 to 3.0, and an FFO/debt ratio range of 9.0 to 13.0.[233] The Commission indicated that those guidelines assumed a credit rating assessment of "strong" for the Alberta regulatory environment. The Commission added that "the guidelines do not take into account potential adjustments to the

[227] Exhibit 27084-X0469.01, PDF pages 5-6.
[228] Exhibit 27084-X0390, PDF page 121.
[229] Exhibit 27084-X0292, PDF page 62.
[230] Exhibit 27084-X0320.02, PDF page 6.
[231] Decision 22570-D01-2018, PDF page 146, paragraph 698.
[232] Proceeding 20622, Exhibit 20622-X0089, PDF page 73.
[233] Decision 22570-D01-2018, PDF page 164, paragraph 775. The guidelines were set out in Table 15 of the decision, on PDF page 165.

deemed equity ratios that may be necessary in the Commission's judgment to take account of the current trend of "negative" noted by credit rating agencies and in particular by S&P."[234]

225. Dr. Villadsen concurred with S&P that it is important to have credit metrics that are not marginally satisfactory.[235] She submitted that to ensure sufficient cushion against negative occurrences, it is important to establish expected credit metrics that are not up against the lower bound, but instead near the middle.[236]

226. N. Martin indicated that under S&P's methodology, regulatory advantage is a key contributor to a utility's credit rating, and submitted that a lower assessment of the regulatory regime leads to higher business risk, and with higher business risk, stronger credit metrics are required to maintain the same rating.[237] N. Martin stated that late in 2020, S&P lowered its assessment of the Alberta "regulatory advantage" from "strong" to "strong/adequate," citing low returns, regulatory lag and the risk of having to absorb undepreciated capital costs of stranded assets. She submitted that simply reducing regulatory lag by improving regulatory efficiency will not be sufficient to improve the regulatory advantage assessment back to "strong."[238]

227. N. Martin submitted that the Commission's sole reliance on ratio targets taken from S&P's low volatility table without also taking into account the medial volatility table is not prudent. She indicated that given Alberta's regulatory advantage is currently only strong/adequate, a utility rating will be based on the low volatility table only if S&P views the utility's business strategy as positive, thus moving the company-specific final regulatory advantage score to strong from strong/adequate.[239]

228. The Commission acknowledges that credit metric targets do not assure an A-range credit rating, but it is satisfied that credit metrics should be considered in the assessment of deemed equity ratios. The Commission recognizes that, among other things, the process of setting credit metrics required to maintain an A-range credit rating for the utilities in Alberta is a function of market dynamics and credit agency analysis of macro-economic trends, Canadian utility industry specific variables and future investor expectations, applied to an assessment of the relative risk of the utility sector, and perceptions of the regulatory environment.

229. Credit metrics reflect past market expectations as well as anticipated market expectations, given an assessment of current economic conditions, the information and assumptions employed in conducting the analysis, and judgment of relative risk. The element of judgment is reflected to some degree in the differing credit metrics employed and the breadth of ranges used by various credit rating agencies and market analysts. Further, the application of utility sector credit metrics to a particular Alberta utility involves a further element of judgment on factors such as the Alberta regulatory climate.

230. From a practical perspective, however, credit metrics affect investor risk perceptions and consequently may affect market behaviour. The Commission considers the credit metrics reflected in credit rating and market analyst reports to be generally reflective of future

[234] Decision 22570-D01-2018, PDF page 164, paragraph 775.
[235] Exhibit 27084-X0761.02, PDF page 76.
[236] Exhibit 27084-X0761.02, PDF page 80.
[237] Exhibit 27084-X0316, PDF page 7.
[238] Exhibit 27084-X0316, PDF page 6.
[239] Exhibit 27084-X0316, PDF page 25.

expectations of utility debt and of equity investors with respect to credit metric fundamentals. This observation is supported generally by a review of actual market behaviour.

231. In the 2016 GCOC decision and the 2018 GCOC decision, the Commission placed greater weight on S&P's credit metric benchmarks for FFO coverage and FFO/debt, using the low volatility table. During the 2018 GCOC proceeding, the Alberta regulatory advantage was rated by S&P as "strong" with a trend of "negative." Evidence was submitted during the current proceeding that late in 2020, S&P lowered its assessment of the Alberta regulatory advantage from "strong" to "strong/adequate." AltaLink and EPCOR submitted that this made the use of the FFO/debt range from S&P's low volatility table inapplicable in this proceeding. J. Coyne submitted that a drop in the regulatory advantage can require stronger credit metrics to maintain a given credit rating. However, the Commission finds that this lower assessment of the Alberta regulatory advantage has not prevented S&P from assessing financial credit metrics for a number of the utilities in Alberta (AltaLink L.P., AltaLink Investments L.P., CU Inc. and Fortis) using the low volatility table.[240]

232. As explained by N. Martin, even with a regulatory advantage assessment of "strong/adequate," S&P's low volatility table will continue to be available, but only if S&P views the utility's business strategy as positive.[241] Given that S&P has viewed the business strategy of a number of the utilities in Alberta as positive, as evidenced by S&P's use of the low volatility table for these utilities, the Commission agrees with the UCA[242] that using the medial volatility table in establishing credit metric thresholds for an A-range rating is unnecessary, and would reward the utilities whose business strategy is not viewed as positive by S&P. The Commission finds that the continued use of the low volatility table is warranted in assessing the credit metrics.

233. The Commission agrees with Dr. Villadsen's submission that it is important to establish credit metrics that are not up against the lower bound, but are nearer to the mid-point of the range. The resulting EBIT coverage ratios at 37 per cent deemed equity are 2.2 for non-taxable utilities and 2.6 for taxable utilities. The DBRS range for EBIT coverage is 1.8 to 2.8, which places the non-taxable utilities just under the mid-point of the range, and places the taxable utilities towards the top of the range. The resulting FFO coverage ratios at 37 per cent deemed equity are 4.4 for the distribution utilities and 3.7 for the transmission utilities. Both of these exceed the 2.0 to 3.0 range of S&P's low volatility table and even exceed the lower bound of the 3.0 to 5.0 range of S&P's medial volatility table. S&P's low volatility table has a range of 9.0 per cent to 13.0 per cent for the FFO/debt ratio. The resulting FFO/debt ratios at 37 per cent deemed equity are 14.2 per cent for the distribution utilities and 11.5 per cent for the transmission utilities, both of which are well above the lower bound of 9.0 per cent, with the distribution utilities being within the range of the medial volatility table.

7.4.1 Equity ratios associated with credit metrics

234. In the 2018 GCOC decision (tables 11-14), the Commission provided a sensitivity analysis to illustrate the effect of a range of equity ratios on the three principal credit metrics for

240 Exhibit 27084-X0926, PDF page 26, citing Exhibit 27084-X0273, PDF pages 134 and 143 (for AltaLink L.P. and AltaLink Investments L.P.), citing Exhibit 27084-X0279, PDF page 66 (for CU Inc.), and citing Exhibit 27084-X0286, PDF page 6 (for Fortis).
241 Exhibit 27084-X0316, PDF page 25.
242 Exhibit 27084-X0926, PDF page 26, paragraph 92.

the distribution utilities and the transmission utilities, using income tax rates of 27 per cent and zero. The analysis was based on certain input parameters associated with the affected utilities. The Commission has prepared a similar analysis as part of this decision.

235. The parameter values used by the Commission in the 2018 GCOC decision, as well as the parameter values the Commission is using in this proceeding, are set out in Table 8 below. The Commission's reasons for selecting the updated parameter values follow.

Table 8. Parameters for calculating credit metrics

Parameter	Parameter values applied in this decision – taxable distribution utilities	Parameter values applied in this decision – taxable transmission utilities	Parameter values applied in 2018 GCOC decision – taxable distribution utilities	Parameter values applied in 2018 GCOC decision – taxable transmission utilities
	(%)			
Embedded average debt rate	4.20	4.20	4.70	4.70
ROE	9.00	9.00	8.50	8.50
Income tax rate	23.00	23.00	27.00	27.00
Depreciation	5.88	4.11	5.85	4.20
CWIP	2.89	3.10	3.21	5.00

236. In arriving at the updated parameters, the Commission reviewed the actual parameters from 2022 and 2021, as set out in the 2023 and 2022 Rule 005 filings that were submitted as part of this proceeding.

237. The ROE input parameter is common to all utilities, as is the income tax rate input parameter for those utilities that are not income tax exempt. The Commission has summarized the embedded average debt rates, depreciation rates and CWIP percentages for each utility in Table 9.

Table 9. Embedded average debt rates, depreciation rates and CWIP percentages by utility

Utility	Invested capital ($000)	Debt cost (%)	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
ATCO Electric – distribution				
2023 Rule 005	2,670,900	4.43	5.14	4.47
2022 Rule 005	2,598,600	4.52	5.05	3.66
Fortis – distribution				
2023 Rule 005	3,929,400	4.44	6.36	1.78
2022 Rule 005	3,777,200	4.42	6.24	1.72
ENMAX – distribution				
2023 Rule 005	1,812,900	3.57	4.95	1.72
2022 Rule 005	1,672,700	3.48	4.93	2.21
EPCOR – distribution				
2023 Rule 005	1,652,300	4.11	4.20	1.45
2022 Rule 005	1,542,500	4.13	4.21	1.73
ATCO Gas – distribution				
2023 Rule 005	2,872,900	4.42	7.57	4.68
2022 Rule 005	2,855,900	4.48	7.24	3.50
Apex – distribution				
2023 Rule 005	452,800	4.27	5.21	1.80
2022 Rule 005	423,800	4.23	5.17	2.81
AltaLink – transmission				
2023 Rule 005	7,421,600	3.89	3.99	1.55
2022 Rule 005	7,469,200	3.86	3.91	1.49
ATCO Electric – transmission				
2023 Rule 005	4,841,400	4.53	4.31	4.84
2022 Rule 005	4,980,300	4.56	4.19	3.23
ENMAX – transmission				
2023 Rule 005	774,100	3.54	3.78	9.70
2022 Rule 005	750,600	3.49	3.67	5.83
EPCOR – transmission				
2023 Rule 005	761,000	4.53	3.64	5.48
2022 Rule 005	732,500	4.60	3.50	5.25
ATCO Pipelines – transmission				
2023 Rule 005	2,486,600	3.97	4.36	1.59
2022 Rule 005	2,344,600	4.06	4.33	2.14
Simple average				
2023 Rule 005		**4.15**	**4.86**	**3.55**
2022 Rule 005		**4.17**	**4.77**	**3.05**

238. In Table 10 below, the Commission presents additional calculations based on the information presented in Table 9. There is no simple average or weighted average for gas transmission utilities presented separately in Table 10 because there is only one gas transmission utility, i.e., ATCO Pipelines.

Table 10. Additional analysis of information included in Table 9

Utility	Debt cost (%)	Depreciation as a percentage of invested capital	Mid-year CWIP as a percentage of invested capital
Simple average – overall			
2023 Rule 005	4.15	4.86	3.55
2022 Rule 005	4.17	4.77	3.05
Weighted average - overall			
2023 Rule 005		4.91	3.01
2022 Rule 005		4.80	2.54
Simple average – distribution utilities			
2023 Rule 005	4.21	5.57	2.65
2022 Rule 005	4.21	5.47	2.60
Weighted average – distribution utilities			
2023 Rule 005		5.88	2.89
2022 Rule 005		5.77	2.61
Simple average – transmission utilities			
2023 Rule 005	4.09	4.01	4.63
2022 Rule 005	4.11	3.92	3.59
Weighted average – transmission utilities			
2023 Rule 005		4.11	3.10
2022 Rule 005		4.03	2.49
Simple average – electric distribution utilities			
2023 Rule 005	4.14	5.16	2.36
2022 Rule 005	4.14	5.11	2.33
Weighted average – electric distribution utilities			
2023 Rule 005		5.43	2.43
2022 Rule 005		5.36	2.33
Simple average – gas distribution utilities			
2023 Rule 005	4.35	6.39	3.24
2022 Rule 005	4.35	6.21	3.15
Weighted average – gas distribution utilities			
2023 Rule 005		7.25	4.29
2022 Rule 005		6.98	3.41
Simple average – electric transmission utilities			
2023 Rule 005	4.12	3.93	5.39
2022 Rule 005	4.13	3.82	3.95
Weighted average – electric transmission utilities			
2023 Rule 005		4.07	3.38
2022 Rule 005		3.98	2.55

239. In its credit metric calculations, the Commission adopted the following five parameters: ROE value, embedded average debt rate, income tax rate, depreciation as a percentage of invested capital, and mid-year CWIP as a percentage of invested capital.

ROE value

240. The Commission has applied the notional ROE value of 9.0 per cent in its credit metric calculations, consistent with its findings in Section 6.4.5.

Embedded average debt rate

241. The simple average of the embedded average debt rates is 4.17 per cent based on the 2022 Rule 005 reports, and 4.15 per cent based on the 2023 Rule 005 reports. The simple average of the distribution utilities based on both Rule 005 reports was 4.21 per cent. The simple

average of the transmission utilities was 4.11 per cent based on the 2022 Rule 005 reports, and 4.09 per cent based on the 2023 Rule 005 reports.

242. The Commission finds that the use of 4.20 per cent for the embedded average debt rate is reasonable. While this figure is higher than the overall simple average debt rate for all the utilities based on the 2023 Rule 005 reports, it errs on the conservative side, because it results in lower EBIT coverage and FFO coverage ratios.

Income tax rate

243. The Commission is analyzing credit metrics using both the current combined statutory income tax rate of 23 per cent, and a rate of zero. The income tax rate of zero accounts for the income-tax-exempt utilities, as well as those utilities that expect to have no taxable income.

Depreciation as a percentage of invested capital

244. The amount of depreciation collected through rates is included in the calculation of the FFO component of the FFO/debt and FFO coverage ratios.

245. The weighted average depreciation rate as a percentage of invested capital for the distribution utilities based on the 2023 Rule 005 reports is 5.88 per cent, and is 4.11 per cent for the transmission utilities, both as shown in Table 10. The Commission uses these figures in its credit metric calculations, because they represent the most recent data on the record of the proceeding.

Mid-year CWIP as a percentage of invested capital

246. The weighted average mid-year CWIP as a percentage of invested capital for the distribution utilities based on the 2023 Rule 005 reports is 2.89 per cent, and is 3.10 per cent for the transmission utilities, both as shown in Table 10. The Commission uses these figures in its credit metric calculations, because they represent the most recent data on the record of the proceeding.

247. Based on the credit metric parameters discussed above, the Commission has updated its credit metric calculations at various equity ratios from the calculations set out in the 2018 GCOC decision. As previously mentioned, to address the impact of zero income tax on credit metrics, the Commission has also provided credit metric calculations at various equity ratios, which reflect an income tax rate of zero. The revised calculations are set out in tables 11-14.

Table 11. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision)

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision
30	2.1	2.0	3.8	3.4	11.9	11.6
31	2.2	2.0	3.9	3.5	12.2	11.9
32	2.2	2.1	4.0	3.6	12.5	12.2
33	2.3	2.2	4.0	3.6	12.8	12.5
34	2.4	2.2	4.1	3.7	13.2	12.8
35	2.4	2.3	4.2	3.8	13.5	13.2
36	2.5	2.3	4.3	3.8	13.8	13.5
37	2.6	2.4	4.4	3.9	14.2	13.8
38	2.6	2.4	4.4	4.0	14.6	14.2
39	2.7	2.5	4.5	4.1	15.0	14.6
40	2.8	2.6	4.6	4.1	15.4	14.9
41	2.9	2.6	4.7	4.2	15.8	15.3
42	2.9	2.7	4.8	4.3	16.2	15.7
43	3.0	2.8	4.9	4.4	16.6	16.2
44	3.1	2.9	5.0	4.5	17.1	16.6
45	3.2	2.9	5.1	4.6	17.5	17.0

Table 12. Credit metrics compared to equity ratios – Commission calculations – distribution utilities – income tax rate of zero

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable
30	1.9	1.7	3.8	3.4	11.9	11.6
31	1.9	1.8	3.9	3.5	12.2	11.9
32	2.0	1.8	4.0	3.6	12.5	12.2
33	2.0	1.8	4.0	3.6	12.8	12.5
34	2.0	1.9	4.1	3.7	13.2	12.8
35	2.1	1.9	4.2	3.8	13.5	13.2
36	2.1	2.0	4.3	3.8	13.8	13.5
37	2.2	2.0	4.4	3.9	14.2	13.8
38	2.2	2.0	4.4	4.0	14.6	14.2
39	2.3	2.1	4.5	4.1	15.0	14.6
40	2.4	2.1	4.6	4.1	15.4	14.9
41	2.4	2.2	4.7	4.2	15.8	15.3
42	2.5	2.2	4.8	4.3	16.2	15.7
43	2.5	2.3	4.9	4.4	16.6	16.2
44	2.6	2.3	5.0	4.5	17.1	16.6
45	2.7	2.4	5.1	4.6	17.5	17.0

Table 13. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of 23 per cent (27 per cent for 2018 GCOC decision)

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision	2023 GCOC decision	2018 GCOC decision
30	2.1	2.0	3.2	2.9	9.4	9.2
31	2.2	2.0	3.3	3.0	9.7	9.4
32	2.2	2.1	3.3	3.0	10.0	9.7
33	2.3	2.1	3.4	3.1	10.2	10.0
34	2.4	2.2	3.5	3.1	10.5	10.2
35	2.4	2.2	3.5	3.2	10.8	10.5
36	2.5	2.3	3.6	3.3	11.1	10.8
37	2.6	2.3	3.7	3.3	11.5	11.1
38	2.6	2.4	3.8	3.4	11.8	11.4
39	2.7	2.5	3.9	3.4	12.1	11.7
40	2.8	2.5	3.9	3.5	12.5	12.1
41	2.8	2.6	4.0	3.6	12.8	12.4
42	2.9	2.7	4.1	3.7	13.2	12.8
43	3.0	2.7	4.2	3.7	13.6	13.1
44	3.1	2.8	4.3	3.8	14.0	13.5
45	3.2	2.9	4.4	3.9	14.4	13.9

Table 14. Credit metrics compared to equity ratios – Commission calculations – transmission utilities – income tax rate of zero

	EBIT coverage		FFO coverage		FFO/debt (%)	
Equity ratio (%)	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable	2023 GCOC decision, non-taxable	2018 GCOC decision, non-taxable
30	1.9	1.7	3.2	2.9	9.4	9.2
31	1.9	1.7	3.3	3.0	9.7	9.4
32	1.9	1.8	3.3	3.0	10.0	9.7
33	2.0	1.8	3.4	3.1	10.2	10.0
34	2.0	1.8	3.5	3.1	10.5	10.2
35	2.1	1.9	3.5	3.2	10.8	10.5
36	2.1	1.9	3.6	3.3	11.1	10.8
37	2.2	2.0	3.7	3.3	11.5	11.1
38	2.2	2.0	3.8	3.4	11.8	11.4
39	2.3	2.1	3.9	3.4	12.1	11.7
40	2.4	2.1	3.9	3.5	12.5	12.1
41	2.4	2.1	4.0	3.6	12.8	12.4
42	2.5	2.2	4.1	3.7	13.2	12.8
43	2.5	2.3	4.2	3.7	13.6	13.1
44	2.6	2.3	4.3	3.8	14.0	13.5
45	2.7	2.4	4.4	3.9	14.4	13.9

248. The Commission has undertaken the above calculations in light of the credit metric findings in Section 7.4. Table 15 sets out the guidelines established by the Commission in this section to achieve a credit rating in the A-range, which assumes S&P viewing the utility's business strategy as positive, which moves the utility's final regulatory advantage score to strong and enables the use of S&P's low volatility table.

249. Table 15 sets out the minimum equity ratio that would be required, in conjunction with an approved ROE of 9.0 per cent, for distribution and transmission utilities in Alberta with an income tax rate of 23 per cent, as well as distribution and transmission utilities in Alberta with an income tax rate of zero per cent, to meet the corresponding credit ratio threshold or range used by the Commission to establish a credit rating in the A-range. For example, as shown in Table 15, a distribution utility in the 2024 GCOC proceeding that has an income tax rate of zero per cent, would require a deemed equity ratio of 32 per cent to achieve an EBIT coverage ratio of 2.0. That same utility would require a deemed equity ratio somewhere below 30 per cent, in order to achieve an FFO coverage ratio of 2.0, and an FFO coverage ratio of 3.0. Finally, that same utility would require a deemed equity ratio below 30 per cent, in order to achieve an FFO/debt ratio of 9.0, while it would require a deemed equity ratio of 34 per cent to achieve an FFO/debt ratio of 13.0.

Table 15. Commission guidelines for equity ratios to achieve a credit rating in the A-range

Credit metric guideline	2.0 EBIT coverage	2.0 FFO coverage	3.0 FFO coverage	9.0 FFO/debt ratio	13.0 FFO/debt ratio
			(%)		
2023 distribution utilities – 23 per cent income tax rate	Below 30	Below 30	Below 30	Below 30	34
2018 distribution utilities – 27 per cent income tax rate	30	Below 30	Below 30	Below 30	35
2023 distribution utilities – zero per cent income tax rate	32	Below 30	Below 30	Below 30	34
2018 distribution utilities – zero per cent income tax rate	36	Below 30	Below 30	Below 30	35
2023 transmission utilities – 23 per cent income tax rate	Below 30	Below 30	Below 30	Below 30	42
2018 transmission utilities – 27 per cent income tax rate	30	Below 30	31	30	43
2023 transmission utilities – zero per cent income tax rate	33	Below 30	Below 30	Below 30	42
2018 transmission utilities – zero per cent income tax rate	37	Below 30	31	30	43

250. Based on the results of its credit metric calculations, the Commission continues to find, as it did in the 2016 and 2018 GCOC decisions, "that absent differences in business risk, the continued perpetuation of the historical gap in equity ratios between the higher equity ratio awarded to distribution utilities and the lower equity ratio awarded to transmission utilities is no longer warranted."[243] Using the credit metric inputs described previously, including the notional ROE of 9.00 per cent, and with the approved deemed equity ratio of 37 per cent, the distribution

243 Decision 22570-D01-2018, PDF page 165, paragraph 777. Decision 20622-D01-2016, PDF page 104, paragraph 433.

and transmission utilities meet the Commission's guidelines to achieve a credit rating in the A range.

7.5 Overall assessment of business risk

251. In this section of the decision, the Commission considers whether business risk factors impacting all the utilities, or a particular segment of the utilities, require the Commission to adjust the deemed equity ratios approved in the 2018 GCOC decision.

252. Utility company witnesses testified that business risk was an important factor underlying their recommended deemed equity ratios. They highlighted the increased business risk to utilities due to elevated cybersecurity concerns, the decarbonization polices of all levels of government along with the increased risk associated with macroeconomic factors of rising inflation, interest rates, and capital costs. More broadly, the Alberta utilities suggested that the overall utilities sector has seen a decline in credit ratings and that Alberta utilities are disadvantaged relative to other Canadian utilities and North American comparators that benefit from regulators approving higher ROEs and equity ratios. Two utilities, Fortis and Apex, argued that they warranted higher equity ratios than other Alberta utilities because of their company-specific business risks.

253. Contrary to the submissions of the utilities, interveners suggested that Alberta utilities operated in a low business risk environment and recommended that equity ratios be maintained at the levels set in the 2018 GCOC or decreased.

254. All parties provided their perspectives on the Alberta-specific utility asset disposition (UAD) related or stranded asset risk and the impact of a recent Court of Appeal decision,[244] which dealt with recovery of costs of stranded assets destroyed by wildfires.

255. Based on the evidence on the record, the Commission identified (i) various macroeconomic factors; (ii) regulatory risk; (iii) UAD risk; and (iv) decarbonization risk as the main grounds offered by utilities for an upward adjustment to equity thickness for all utilities. A discussion of these issues is provided below, followed by a discussion of the utility-specific risks of Fortis and Apex.

7.5.1 Macroeconomic factors

256. While the Commission acknowledges that interest rates and inflation have increased since the 2018 GCOC, resulting in higher capital costs, it is not persuaded that these factors warrant an increase in approved ROEs or deemed equity ratios above those currently in place. In Alberta, the utilities are largely isolated from broader macroeconomic factors because utility regulation provides a reasonable opportunity to recover prudently incurred costs, including those directly and indirectly affected by higher interest and inflation rates.[245] Specifically, PBR plans for Alberta distribution utilities include inflation as a direct input into the PBR formula, while cost-of-service (COS) regulation that applies to transmission utilities affords those utilities a reasonable opportunity to recover all reasonable forecast cost increases related to the safe, reliable and efficient provision of services to customers over the future test period.[246]

[244] *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.
[245] Exhibit 27084-X0918, PDF page 14, citing Transcript, Volume 2, pages 504-509.
[246] Exhibit 27084-X0918, PDF page 14.

7.5.2 Regulatory risk

257. The utilities claim that regulatory risks in Alberta have increased since 2018. Among the risks they have identified are lower deemed equity ratios and lower approved ROEs than those awarded in other North American jurisdictions, regulatory lag, stranded asset risk, and one credit rating agency's lowering of its assessment of the Alberta regulatory advantage from "most credit supportive" (strong) to "highly credit supportive" (strong/adequate).[247]

258. The Commission finds these claims of higher regulatory risk in Alberta are without merit. Alberta utilities have low earnings volatility, low business risk ratings and, operate within a regulatory framework that encourages and rewards utility-driven initiatives, projects, and investments in cost reduction and efficiency improvement that can lead to earnings in excess of approved ROEs (that themselves have been determined to be just and reasonable independently of, and entirely without regard to, any additional profits arising from such cost-cutting initiatives) during each PBR term or COS test period.[248] The Commission notes parenthetically in this regard, that, with very few exceptions, Alberta utilities have, on average, consistently earned returns above their approved ROE during the past 17 years by responding positively to existing incentives to drive costs lower and secure the benefit of savings thus generated until the next rate case or PBR term. Moreover, regulatory lag, regulatory costs, red tape and related aspects of regulatory burden have been significantly reduced in Alberta since the 2018 GCOC proceeding.[249]

259. On balance, the Commission finds that the regulatory environment for Alberta utilities is broadly supportive, and that the level of regulatory risk faced by the Alberta utilities is consistent with the level of regulatory risk they faced at the time of the 2018 GCOC proceeding, if not distinctly lower. The issue of stranded asset or UAD-related risk, meanwhile, is dealt with separately in the next section.

7.5.3 Utility asset disposition risk and the impact of the Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129

260. In a letter dated June 6, 2023,[250] the Commission requested that parties provide submissions on the impact of the Court of Appeal decision in *ATCO Electric Ltd. v Alberta Utilities Commission*[251] (the Wildfires Decision) on business risk related to the recovery of costs associated with assets that are stranded due to obsolescence.

261. Most parties submitted that it was premature to assess the impact of the Wildfires Decision – which dealt with the recovery of assets destroyed by a natural disaster – on the recovery of stranded assets made obsolete by technology or other causes. This is because the Court of Appeal sent the matter back to the Commission to determine, and the Commission has not yet rendered its decision. Until the Commission reconsiders its decision on the UAD framework, utilities argued that they were exposed to uncertainty and UAD-related cost disallowance. The CCA stated that the Wildfires Decision likely reduces the business risk of

[247] Exhibit 27084-X0316, PDF pages 17-18; Exhibit 27084-X0390, PDF page 97.
[248] As noted in footnote 192, The Commission recognizes that utilities subject to COS regulation do not have the same incentives and returns as utilities subject to PBR.
[249] AUC website: https://www.auc.ab.ca/auc-exceeds-government-of-alberta-target-with-48-per-cent-reduction-in-regulatory-red-tape-requirements/#hq=red%20tape%20reduction
[250] Exhibit 27084-X0906, AUC letter – Additional details regarding argument process.
[251] *ATCO Electric Ltd. v Alberta Utilities Commission*, 2023 ABCA 129.

utilities as it appears to directionally increase the likelihood of recovery of costs from customers due to weather and natural disaster events.[252]

262. Apart from any impact the Commission's reconsideration of the Wildfires Decision may have, there is no compelling basis to suggest that UAD-related risk has changed since the decision in the 2018 GCOC. The Commission also finds that its 2016 GCOC decision[253] is still applicable to the present proceeding. There, the Commission found that regulatory risk for investors in Alberta utilities had increased by some incremental but unquantifiable amount as a result of the Stores Block-Utility Asset Disposition line of decisions.[254]

7.5.4 Decarbonization

263. The Commission finds that while there are numerous legislative and other initiatives at all levels of government to reduce carbon emissions,[255] the record of this proceeding does not establish that progress towards decarbonization that has taken place or is reasonably likely to take place in the foreseeable future, poses an immediate or imminent risk to Alberta utilities warranting an adjustment to their equity thickness.

264. The utilities argued that, generally, carbon reduction goals are more aggressive and difficult in Alberta than decarbonization policies in other jurisdictions. Examples include the current federal government's stated intention to decarbonize the electricity grid by 2035 and the transition to electric heating now overwhelmingly provided by natural gas. The utilities asserted that if decarbonization creates stranded assets (as it is designed to), the current recovery mechanism (the UAD line of cases) as applied by the Commission to date is much less supportive than in other jurisdictions, thus increasing the utilities' business risk.

265. Interveners disagreed with this view, stating that absent actual evidence that decarbonization increases the risk to Alberta utilities, there should be no resulting adjustment to equity thickness.[256] To the contrary, they submitted that decarbonization and net-zero policies would benefit electric utilities because in order to achieve these goals, additional investment in distribution infrastructure, for example, changes to accommodate wide penetration of electric vehicle charging would be required, thus increasing the utility's rate base and load. Interveners did acknowledge that there may be impacts on natural gas utilities but that the actual impact was uncertain at this time given the present status of hydrogen injection into the natural gas distribution stream. They concluded that Alberta's overwhelming reliance on natural gas for space heating is not likely to change in the near term because of the very high cost of transitioning from natural gas to electricity.[257]

266. While the Commission appreciates that decarbonization is a potential risk to Alberta utilities, there is little or no evidence on the record of the current proceeding that shows that natural gas or electric utilities have experienced any significant increases in risk related to customers changing behaviour, a reduction in natural gas demand, complications related to electrification, or factors that might impact their operations. Absent any evidence that clearly shows the impact to the Alberta utilities' business risk from decarbonization, the Commission

252 Exhibit 27084-X0919, PDF page 26, paragraph 82.
253 Decision 20622-D01-2016.
254 Decision 20622-D01-2016, PDF pages 120-121.
255 Exhibit 27084-X0479, PDF pages 29-31.
256 Exhibit 27084-X0934, PDF page 5.
257 Exhibit 27084-X0926, PDF pages 27-28.

finds that adjusting the deemed equity ratio for Alberta utilities to account for any such impact is unwarranted, or at a minimum, premature.

7.6 Utility-specific business risks

7.6.1 Determination of Commission-approved deemed equity ratio for Fortis

267. Fortis requested a 300 bps premium above the generic deemed equity ratio for an Alberta utility on the basis that it faces increased business and regulatory risk not experienced by other Alberta utilities. Specifically, Fortis argued that these risks arise from the increased competition for customers from rural electrification associations (REAs) and the removal from its recoverable revenue requirement of over $10 million on an ongoing annual basis beginning in 2023. The removal of the $10 million from revenue requirement resulted from a Commission decision[258] which was subsequently upheld by the Court of Appeal of Alberta.[259] Fortis estimated that this will reduce Fortis's earned ROE by approximately 68 bps and erode its cash flow credit metrics, which might result in a credit rating downgrade.[260]

268. The Commission is not persuaded that an increase in the equity thickness is required. As pointed out by the UCA, the threat of competition from REAs is negligible at present. A net total of just 35 sites has transferred to REAs since 2018, which the UCA calculated as 0.006 per cent of customers in Fortis's service territory.[261] The Commission is not persuaded that there is a serious threat of customer defections from Fortis to REAs. Further, the Commission finds that increasing Fortis's equity thickness to counter competition from REAs would place Fortis at a competitive disadvantage relative to REAs as an increase in equity thickness will result in an increased revenue requirement, and ultimately higher rates for Fortis's customers.

269. In addition, increasing the equity thickness by 300 bps in order to offset the removal of $10 million from Fortis's revenue requirement is compensating Fortis indirectly for what the Commission does not have the authority to do directly, that is, to compensate Fortis for costs attributable to the REAs' use of Fortis's system from Fortis's own regulated customers.[262]

270. In upholding the Commission's decision to deny recovery of these costs from Fortis customers, the Court of Appeal in the EQUS REA decision stated:[263]

> [23] The Commission correctly determined that FortisAlberta cannot recover from its customers the difference between the costs FortisAlberta incurs when rural electrification associations use FortisAlberta's distribution system to provide electricity to its members and the costs rural electrification associations incur when FortisAlberta uses rural electrification associations' distribution systems to provide electricity to its customers. There is no sound reason why FortisAlberta's customers should subsidize the members of rural electrification associations.

[258] Decision 25916-D01-2021: FortisAlberta Inc., 2022 Phase II Distribution Tariff Application, Proceeding 25916, July 8, 2021.
[259] *Equs Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142.
[260] Exhibit 27084-X0479, PDF page 47.
[261] Exhibit 27084-X0926, PDF page 31, paragraph 110.
[262] This point was also made by the UCA and IPCAA – see Exhibit 27084-X0926, PDF page 30, paragraph 108; Exhibit 27084-X0918, PDF pages 20-21, paragraph 64.
[263] *Equs Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142.

271. Granting an increase in Fortis's deemed equity ratio would result in such subsidization, although in an indirect as opposed to direct way.

272. IPCAA further argued the Commission should not award higher returns to Fortis for an unregulated business risk.[264] The CCA made a similar argument, submitting that the charges are not related to utility service and should, therefore, have no impact on the cost of capital.[265]

273. The Commission finds that the proper course for recovery of costs associated with intermingled service provided to REAs by Fortis is through negotiation and arbitration of integrated operating agreements under the *Roles, Relationships and Responsibilities Regulation*. While Fortis has not enjoyed success recently under that framework, it is the statutorily sanctioned mechanism and is available to Fortis as integrated operating agreements terminate and are renegotiated.

7.6.2 Determination of Commission-approved deemed equity ratio for Apex

274. Apex submitted that its deemed equity ratio should be 400 bps higher than the deemed equity ratio of the average distribution utility because it faces higher business and operational risks than other distribution utilities in Alberta. These risks, it argued, arise because of Apex's small size, geographically dispersed service territory in rural Alberta and gas supply risk.

275. The Commission accepts that these aspects of Apex's size, operations and service territory do create additional risks compared to other distribution companies but not to the extent of an additional 400 bps above the other utilities. The Commission acknowledges that for several years until 2018, it approved an additional 400 bps of equity thickness in excess of the other Alberta utilities to address these risks. The additional equity was intended to meet the business and operational risks that Apex faced. The extra equity thickness provided the utility with greater revenues than would otherwise be the case, in order to compensate for the inability to generate, for example, the cost savings and efficiencies that come from economies of scale that large, mostly urban utilities like ATCO Gas enjoy.

276. However, in the 2018 GCOC decision, the Commission reduced the equity thickness from 41 per cent to 39 per cent because, notwithstanding the additional 400 bps to AltaGas (now Apex), AltaGas's parent[266] (which borrowed money in financial markets and passed it down to AltaGas) was unable to raise debt at an A-range credit rating resulting in customers paying for costs associated with additional equity thickness but without receiving the benefit of lower debt costs.[267] The decision to reduce the equity thickness, the Commission stated, was in keeping with "… the Commission's duty to set a fair return for AltaGas as an element of the just and reasonable rates to be paid by its customers."[268]

277. In the current proceeding, the record shows that even with an extra 400 bps, Apex's current parent, TriSummit, would not achieve an A-rated credit rating because of its relatively small size.[269] Apex argued that TriSummit, which continues to issue public debt instruments to fund Apex's operations and rate base, has a similar business risk profile to its own. For example,

264 Exhibit 27084-X0918, PDF page 20, paragraph 62.
265 Exhibit 27084-X0919, PDF page 26, paragraph 80.
266 Apex was previously known as AltaGas Utilities Inc., and its parent was AltaGas Ltd.
267 Decision 22570-D01-2018, PDF page 176, paragraph 840.
268 Decision 22570-D01-2018, PDF page 176, paragraph 837.
269 Exhibit 27084-X0377, PDF page 20.

80 per cent of TriSummit's assets are regulated utility operations with 95 per cent of its revenue earned from those operations. With this profile, TriSummit has a BBB high credit rating.

278. Apex argued that TriSummit's credit rating and borrowing cost represent an accurate proxy for the market cost of debt for Apex as a stand-alone entity, and that Apex requires an additional 400 bps above the generically deemed equity ratio to achieve the BBB high credit rating of its parent in order to maintain a fair ROE. Additional equity provides a utility with a better opportunity to achieve higher interest coverage ratios while reducing the financial risk to the utility.

279. The Commission finds that the focus in determining Apex's equity thickness should be on the risks identified in 2018 compared to the business risks that it currently faces. In the Commission's view, the risks resulting from Apex's small size, geographically dispersed service areas in mostly rural Alberta and its reliance on third party suppliers have not materially changed since then nor are expected to change in the near future. And there is little, if any, concrete evidence that Apex's financial integrity or its ability to attract investment has been unduly impaired at its current equity thickness of 39 per cent established in 2018.

280. The Commission notes, as interveners have argued, that the fact that the ownership of Apex's parent company has changed twice since the 2018 GCOC decision, most recently in 2020 when pension funds acquired all the outstanding shares of Apex's prior parent, AltaGas Canada Ltd. in a take-private transaction, demonstrates that equity financing is readily available.[270] The Commission also finds that Apex's exposure to the abandonment of third-party laterals that it relies on to supply gas to its distribution network has also remained unchanged since 2018. Apex may well have to purchase or build new laterals itself, but there is little compelling evidence that these risks have increased or will increase, or that a 39 per cent equity thickness undermines Apex's ability respond to these contingencies.

281. In the Etzikom decision[271] referred to by Apex as an example of this risk, the Commission approved construction of a new lateral but denied recovery of these costs under the then PBR framework that governed access to additional capital. Essentially, the Commission found that sufficient funds had been approved in the going-in rates at the beginning of the 2018-2022 PBR term to meet the abandonment of third-party laterals. The Commission stated at paragraph 30:

> The Commission has learned that the distribution utilities have considerable flexibility in dealing with the timing of their capital programs and are capable of accommodating many changes in circumstances without any immediate concerns about service quality and meeting their obligation to serve.

282. In summary, the Commission finds that Apex's risks have not materially changed since 2018 when a 39 per cent equity thickness was awarded to it. Apex has maintained financial integrity and has been able to attract capital on reasonable terms notwithstanding that it enjoyed a higher equity thickness prior to 2018. Further, as TriSummit has a better credit rating than Apex's previous parent, although still not A-rated, the Commission finds that a higher equity

[270] Exhibit 27084-X0926, PDF pages 31-32, paragraph 113, Transcript, Volume 1, pages 249-250.
[271] Decision 25608-D01-2020: AltaGas Utilities Inc., Type 1 Capital Tracker True-Up – Etzikom Lateral Project, Proceeding 25608, October 16, 2020.

thickness is not warranted. The result is that the Commission approves a 39 per cent equity thickness, 200 bps above the generic equity thickness approved for the other utilities.

8 Order

283. It is hereby ordered that:

(1) The final approved generic return on equity for Apex Utilities Inc. AltaLink Management Ltd. and its partners PiikaniLink L.P. and KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is to be set using the methods approved in this decision on an annual basis, beginning in 2024, until determined otherwise by the Commission.

(2) The final approved deemed equity ratio for AltaLink Management Ltd., PiikaniLink L.P., KainaiLink L.P., ATCO Electric Ltd., ATCO Gas, ATCO Pipelines, ENMAX Power Corporation, EPCOR Distribution & Transmission Inc., FortisAlberta Inc., the transmission operations of the City of Lethbridge, the transmission operations of The City of Red Deer, and certain electricity transmission assets of TransAlta Corporation, is set at 37 per cent. The final approved deemed equity ratio for Apex Utilities Inc. is 39 per cent. These final approved deemed equity ratios are effective January 1, 2024, until determined otherwise by the Commission.

Dated on October 9, 2023.

Alberta Utilities Commission

(original signed by)

Douglas A. Larder, KC
Vice-Chair

(original signed by)

Renée Marx
Commission Member

(original signed by)

Bohdan (Don) Romaniuk
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Direct Connect Consumers Association (ADC)
AltaLink Management Ltd. (AltaLink) Borden Ladner Gervais LLP ScottMadden, Inc.
Apex Utilities Inc. (Apex) MLT Aikins LLP The Brattle Group
ATCO Electric Ltd. (ATCO Electric) Bennett Jones LLP The Brattle Group
ATCO Gas Bennett Jones LLP The Brattle Group
Capital Power Corporation (CPC) Dentons Canada LLP
Consumers' Coalition of Alberta (CCA)
ENMAX Power Corporation (ENMAX or EPC) Torys LLP Nicole Martin Concentric Energy Advisors, Inc. James Coyne
EPCOR Distribution & Transmission Inc. (EPCOR or EDTI) Borden Ladner Gervais LLP ScottMadden, Inc.
FortisAlberta Inc. (Fortis or FAI) Fasken Martineau DuMoulin LLP The Brattle Group
Industrial Power Consumers Association of Alberta (IPCAA) Ackroyd LLP
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP Russ Bell & Associates Inc.

Alberta Utilities Commission

Commission panel
D.A. Larder, KC, Vice-Chair
R. Marx, Commission Member
B. Romaniuk, Acting Commission Member

Commission staff
L. Berg (Commission counsel)
A. Marshall (Commission counsel)
A. Jukov
D. Mitchell
M. McJannet
K. O'Neill
K. Taylor

Appendix 2 – Oral hearing – registered appearances

Name of organization (abbreviation) Name of counsel or representative	Witnesses
AltaLink Management Ltd. (AltaLink) and EPCOR Distribution Inc. (EPCOR) J. Liteplo/J. Hulecki	D. D'Ascendis
Apex Utilities Inc. (Apex) R. Jeerakathil	B. Villadsen F. Graves M. Tolleth M. Stock D. Makarenko
ATCO Utilities (ATCO Electric Ltd. and ATCO Gas and Pipelines) T. Myers L. Smith	B. Villadsen F. Graves
FortisAlberta Inc.(Fortis) A. Sears	B. Villadsen F. Graves B. Hendersen
ENMAX Power Corporation (ENMAX) D. Wood/T. Campbell	J. Coyne J. Trogonoski N. Martin
Consumers' Coalition of Alberta (CCA) J.A. Wachowich	J. Thygesen
Industrial Power Consumers Association of Alberta (IPCAA) R. Secord	D. Madsen
Office of the Utilities Consumer Advocate (UCA) R. McCreary/B. Schwanak	R. Bell S. Cleary

Alberta Utilities Commission Commission panel D.A. Larder, KC, Vice-Chair R. Marx, Commission Member B. Romaniuk, Acting Commission Member Commission staff L. Berg (Commission counsel) A. Marshall (Commission counsel) A. Jukov D. Mitchell M. McJannet

Appendix 3 – Summary of Commission directions

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

1. The record of this proceeding includes some monthly data for the base utility bond yield spread but the average daily spread for February 2023 is not available on the record and its calculation requires proprietary data (Bloomberg Series C29530Y). Therefore, the Commission directs the ATCO Utilities, who sponsored the evidence of Dr. Villadsen, to calculate the average utility bond yield spread for the period from February 1 to February 28, 2023 using the calculation steps described in her evidence. The ATCO Utilities are further directed to provide these calculations and the resulting utility bond yield spread value as a post-disposition filing to this proceeding by October 18, 2023. Once confirmed by the Commission, this value will be used as the base utility bond yield spread ($SPRD_{base}$) in the approved formula. .... paragraph 200

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Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.81]

Question(s):

Concentric states: “As discussed earlier, Ontario utilities are competing for capital with other North American utilities, and this competition will become even more accentuated in the Energy Transition, as utilities vie for limited investor capital.” Please provide specific examples of CLD+ utilities that have had trouble attracting capital as a result of the OEB’s approved capital structure and ROE.

Response:

Please see the response to N-M2-11-OEB Staff-17(a).

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.84]

Question(s):

Concentric states: “Concentric has included an adjustment of 50 basis points to the results of our DCF and CAPM results for flotation costs and financial flexibility, consistent with prior precedent in Ontario as well as most other Canadian jurisdictions”:

a) What exactly is included in flotation costs?

b) What is meant by financial flexibility?

c) With respect to flotation costs, please provide evidence from CLD+ utilities’ actual costs to demonstrate that 50 basis points is a reasonable amount.

d) Please confirm that at least some CLD+ utilities (e.g. Hydro One, Toronto Hydro) add 5 basis points to individual debt instruments to reflect administration costs. If confirmed, please explain why 50 basis points is appropriate for similar category of costs for the purposes of the ROE.

Response:

a) See response to N-M2-10-OEB Staff-16(a).

b) See response to N-M2-10-OEB Staff-16(a).

c) See response to N-M2-10-OEB Staff-16(a).

d) Confirmed. Please see the response to N-M2-10-OEB Staff-16(a) as to why the 50 basis points adjustment is appropriate for issuing common equity.

<u>Ontario Energy Association (OEA)</u>

Answer to Interrogatory from
<u>School Energy Coalition (SEC)</u>

<u>INTERROGATORY</u>

<u>Reference:</u>

[M2, p.126]

<u>Question(s)</u>:

With respect to Fuel Price Risk, Concentric states: “Like the Ontario utilities, the North American proxy group companies have little to no exposure to commodity price risk or supply risk due either to the elimination of the utility supply function in competitive electric and gas markets or through the prevalence of fuel pass-through mechanisms – 100 percent of the proxy companies are protected from normal commodity price risk.” Please identify which non-Ontario electric utilities included in the North American proxy group as Load Serving Entities (or similar role) in which they procure electricity supply on behalf of at least some of its customers. For those utilities, please explain if those documents are subject to any form of prudence review, even if the amounts are treated as pass-through costs.

<u>Response:</u>

Concentric is aware that several Northeast utilities in the U.S., including the electric operating utilities owned by Eversource Energy, have the Load Serving Entities (“LSE”) function and procure electricity supply on behalf of customers. The contracts for this supply are subject to prudence review as to the reasonableness of the costs. In Ontario, electric distribution utilities such as Hydro One do not have the LSE function; that role is served by the Ontario IESO. Ontario electric distributors have no legal obligation to provide electricity supply, only to connect customers. In that regard, Ontario’s electric distribution utilities have lower risk than electric utility companies that have the LSE obligation. This situation, however, has not changed since the 2009 review of the Ontario formula or since 2006, when the OEB set the deemed equity ratio for electric distributors at 40%. Furthermore, the Ontario electric distributors are responsible for billing all parts of the end use electricity customers bill, generation, transmission, and regulatory charges, and manage the related bad debt. Although these costs are intended to be flowthrough charges, distributors manage the cashflow impacts of rates charged to customer not being equal to what is charged to distributors and hold the risk of settlement errors. Distributors also settle for some generators. Lastly, the OEB has new requirements for Ontario electric distributors to consider non-wires solutions as part of their Distribution System Plan and Ontario distributors are taking on new roles in the Ontario Market in order to support load growth, grid modernization and the expanded use of DERs.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.126]

Question(s):

With respect to Volume Risk:

a) Concentric states that: “Approximately 62 percent of the operating utilities held by the North American proxy groups are protected from market (or demand) risk by full or partial revenue decoupling mechanisms.” For each North American proxy group companies, please specify which utility is protected from “market (or demand) risk by full or partial revenue decoupling mechanisms” and the details of the specific mechanism.

b) Concentric states: “The majority of Ontario’s electric distribution utilities also have a regulatory mechanism to mitigate volumetric risk.” Which Ontario electricity distribution utilities do not have a regulatory mechanism to mitigate volumetric risk?

c) Please confirm that all Ontario electricity distributors are protected against residential customer volumetric risk as a result of full fixed residential distribution rates.

d) Do any non-Ontario electric utilities in the North American proxy group companies have full fixed distribution rates for residential or any other rate class? If so, please provide details.

Response:

a) Please see N-M2-10-SEC-51(a), Attachment 1 for the requested information for the operating utilities held by the North American proxy group companies. Concentric has not researched the details of the specific revenue decoupling mechanisms for each of the 132 operating companies.

b) Concentric's understanding is that all of Ontario's electric distribution utilities have a regulatory mechanism to mitigate volumetric risk.

c) Confirmed.

d) Concentric has not researched each of the specific revenue decoupling mechanisms for the 132 operating companies and so Concentric is not aware of any electric utilities in the North American proxy group that have full fixed distribution rates. As shown in SEC-51(a), Attachment 1, there are eight electric operating utilities that have full revenue decoupling (not including Hydro One).

North American Combined Proxy Group - Decoupling Mechanisms

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	[1] Full Decoupling	[1] Partial Decoupling
Canadian Proxy Group						
AltaGas Limited	ALA	ENSTAR Natural Gas Company	Natural Gas	AK		
		Washington Gas Light Company	Natural Gas	DC		
		Washington Gas Light Company	Natural Gas	MD		✓
		SEMCO Energy, Inc.	Natural Gas	MI		
		Washington Gas Light Company	Natural Gas	VA		✓
Canadian Utilities Limited	CU	ATCO Electric	Electric	Alberta		
		ATCO Gas	Natural Gas	Alberta		✓
Emera Inc.	EMA	Tampa Electric Company	Electric	FL		
		Peoples Gas System	Natural Gas	FL		
		New Mexico Gas Company, Inc.	Natural Gas	NM		✓
		Nova Scotia Power Inc.	Electric	Nova Scotia		✓
Enbridge	ENB	Enbridge Gas	Natural Gas	Ontario		✓
		Gazifere	Natural Gas	Quebec		
Fortis Inc.	FTS	Central Hudson Gas & Electric Corp.	Electric	NY	✓	
		Central Hudson Gas & Electric Corp.	Natural Gas	NY	✓	
		Tucson Electric Power Company	Electric	AZ		✓
		UNS Electric, Inc.	Electric	AZ		✓
		UNS Gas, Inc.	Natural Gas	AZ		✓
		FortisAlberta	Electric	Alberta		
		FortisBC	Electric	British Columbia	✓	
		FortisBC Energy	Natural Gas	British Columbia	✓	
		Newfoundland Power Inc	Electric	Newfoundland & Labrador		✓
		Maritime Electric Company Ltd.	Electric	Prince Edward Island		✓
HydroOne Inc.	H	Hydro One Inc.	Electric	Ontario	✓	

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
U.S. Electric Proxy Group						
Alliant Energy Corporation	LNT	Interstate Power and Light Company	Electric	IA		
		Interstate Power and Light Company	Natural Gas	IA		
		Wisconsin Power and Light Company	Electric	WI		
		Wisconsin Power and Light Company	Natural Gas	WI		
Ameren Corporation	AEE	Ameren Illinois Company	Electric	IL		✓
		Ameren Illinois Company	Natural Gas	IL		✓
		Union Electric Company	Electric	MO		✓
		Union Electric Company	Natural Gas	MO		✓
American Electric Power Company, Inc.	AEP	Southwestern Electric Power Company	Electric	AR		✓
		Indiana Michigan Power Company	Electric	IN		✓
		Kentucky Power Company	Electric	KY		✓
		Southwestern Electric Power Company	Electric	LA		✓
		Indiana Michigan Power Company	Electric	MI		✓
		Ohio Power Company	Electric	OH		✓
		Public Service Company of Oklahoma	Electric	OK		✓
		Kingsport Power Company	Electric	TN		
		AEP Texas Inc.	Electric	TX		
		Southwestern Electric Power Company	Electric	TX		
		Appalachian Power Company	Electric	VA		
		Wheeling Power Company	Electric	WV		
Duke Energy Corporation	DUK	Duke Energy Florida, LLC	Electric	FL		
		Duke Energy Indiana, LLC	Electric	IN		✓
		Duke Energy Kentucky, Inc.	Electric	KY		✓
		Duke Energy Kentucky, Inc.	Natural Gas	KY		✓
		Duke Energy Carolinas, LLC	Electric	NC		
		Duke Energy Progress, LLC	Electric	NC		
		Piedmont Natural Gas Company, Inc.	Natural Gas	NC	✓	
		Duke Energy Ohio, Inc.	Electric	OH		✓
		Duke Energy Ohio, Inc.	Natural Gas	OH		
		Duke Energy Progress, LLC	Electric	SC		
		Duke Energy Carolinas, LLC	Electric	SC		
		Piedmont Natural Gas Company, Inc.	Natural Gas	SC		✓
		Piedmont Natural Gas Company, Inc.	Natural Gas	TN		✓

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
Entergy Corporation	ETR	Entergy Arkansas, LLC	Electric	AR		✓
		Entergy New Orleans, LLC	Electric	LA		
		Entergy New Orleans, LLC	Natural Gas	LA		
		Entergy Louisiana, LLC	Electric	LA		✓
		Entergy Mississippi, LLC	Electric	MS		✓
		Entergy Texas, Inc.	Electric	TX		
Eversource Energy	ES	The Connecticut Light and Power Company	Electric	CT	✓	
		Yankee Gas Services Company	Natural Gas	CT	✓	
		Eversource Gas Company of Massachusetts	Natural Gas	MA	✓	
		NSTAR Electric Company	Electric	MA	✓	
		NSTAR Gas Company	Natural Gas	MA	✓	
		Public Service Company of New Hampshire	Electric	NH		✓
Evergy, Inc.	EVRG	Evergy Kansas Central, Inc.	Electric	KS		✓
		Evergy Kansas South, Inc.	Electric	KS		✓
		Evergy Metro, Inc.	Electric	KS		
		Evergy Metro, Inc.	Electric	MO		✓
		Evergy Missouri West, Inc.	Electric	MO		✓
Exelon Corporation	EXC	Delmarva Power & Light Company	Electric	DE		
		Delmarva Power & Light Company	Natural Gas	DE		
		Potomac Electric Power Company	Electric	DC		✓
		Commonwealth Edison Company	Electric	IL		
		Baltimore Gas and Electric Company	Electric	MD	✓	
		Baltimore Gas and Electric Company	Natural Gas	MD	✓	
		Delmarva Power & Light Company	Electric	MD	✓	
		Potomac Electric Power Company	Electric	MD	✓	
		Atlantic City Electric Company	Electric	NJ		✓
		PECO Energy Company	Electric	PA		
		PECO Energy Company	Natural Gas	PA		
NextEra Energy, Inc.	NEE	Florida Power & Light Company	Electric	FL		
		Pivotal Utility Holdings, Inc.	Natural Gas	FL		
		Lone Star Transmission, LLC	Electric	TX		

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
OGE Energy Corporation	OGE	Oklahoma Gas and Electric Company	Electric	AR		✓
		Oklahoma Gas and Electric Company	Electric	OK		✓
Pinnacle West Capital Corporation	PNW	Arizona Public Service Company	Electric	AZ		✓
PPL Corporation	PPL	Kentucky Utilities Company	Electric	KY		✓
		Louisville Gas and Electric Company	Electric	KY		✓
		Louisville Gas and Electric Company	Natural Gas	KY		✓
		PPL Electric Utilities Corporation	Electric	PA		
		The Narragansett Electric Company	Electric	RI	✓	
		The Narragansett Electric Company	Natural Gas	RI	✓	
		Kentucky Utilities Company	Electric	VA		
Portland General Electric Company	POR	Portland General Electric Company	Electric	OR		
Southern Company	SO	Alabama Power Company	Electric	AL		
		Atlanta Gas Light Company	Natural Gas	GA		
		Georgia Power Company	Electric	GA		
		Northern Illinois Gas Company	Natural Gas	IL		✓
		Mississippi Power Company	Electric	MS		✓
		Chattanooga Gas Company	Natural Gas	TN	✓	
		Virginia Natural Gas, Inc.	Natural Gas	VA		✓
Xcel Energy Inc.	XEL	Public Service Company of Colorado	Electric	CO		✓
		Public Service Company of Colorado	Natural Gas	CO		✓
		Northern States Power Company	Electric	MN		✓
		Northern States Power Company	Natural Gas	MN		
		Southwestern Public Service Company	Electric	NM		
		Northern States Power Company	Electric	ND		
		Northern States Power Company	Natural Gas	ND		
		Northern States Power Company	Electric	SD		✓
		Southwestern Public Service Company	Electric	TX		
		Northern States Power Company	Electric	WI		
		Northern States Power Company	Natural Gas	WI		

Company	Ticker	Operating Subsidiary	Service Type	Jurisdiction	Full Decoupling	Partial Decoupling
US Gas Proxy Group						
Atmos Energy Corp	ATO	Atmos Energy Corporation	Natural Gas	CO		
		Atmos Energy Corporation	Natural Gas	KS		✓
		Atmos Energy Corporation	Natural Gas	KY		✓
		Atmos Energy Corporation	Natural Gas	LA		✓
		Atmos Energy Corporation	Natural Gas	MS		✓
		Atmos Energy Corporation	Natural Gas	TN		✓
		Atmos Energy Corporation	Natural Gas	TX		✓
Northwest Natural Holding Company	NWN	Northwest Natural Gas Company	Natural Gas	OR		✓
		Northwest Natural Gas Company	Natural Gas	WA		
ONE Gas, Inc.	OGS	Kansas Gas Service Company, Inc.	Natural Gas	KS		✓
		Oklahoma Natural Gas Company	Natural Gas	OK		✓
		Texas Gas Service Company, Inc.	Natural Gas	TX		✓
Spire, Inc.	SR	Spire Missouri Inc.	Natural Gas	MO		✓
		Spire Alabama Inc.	Natural Gas	AL		✓
		Spire Gulf Inc.	Natural Gas	AL		✓

Proxy Group Results	**Total:**		
	132	18	64
		14%	48%

Notes:

[1] Source: US companies are based on Regulatory Research Associates, "Adjustment Clauses: A State by State Overview", July 18, 2022. Canadian companies are from Annual Repo

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.130]

Question(s):

Please confirm the significant use by the Government of Ontario of its authority under section 96.1 of the Ontario Energy Board Act, which designates transmission projects as priority projects and requires the OEB to accept the need for the project, reduces risk for transmitters.

Response:

The Government of Ontario has used its authority under section 96.1 of the *Ontario Energy Board* Act on several occasions. Section 96.1 establishes the need for transmission projects (somewhat reducing risk, although as a practical matter transmitters are not likely to move forward with regulated projects for which there is not a high likelihood of a need being established) but doesn’t establish cost recovery for them.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.133]

Question(s):

Please reconcile Concentric's recommendation for an equity thickness of 42% for Enbridge Gas in EB-2022-0200, with its recommendation for an equity thickness of 45% for all utilities (which include Enbridge Gas).

Response:

In EB-2022-0200, Concentric recommended that Enbridge Gas, Inc.'s equity ratio be set between 40% and 45%, and, within that range, recommended the OEB authorize a common equity ratio of 42% for the Company. Concentric also recognized that, at the time, OPG's equity ratio of 45% likely set a ceiling for the OEB on the appropriate authorized equity ratio for Enbridge Gas, and was of the view that the equity ratio for electric distributors of 40% was a floor for Enbridge Gas, Inc.'s equity ratio. Lastly, Concentric recognized that, based on its risk assessment in EB-2022-0200, its recommendation was conservative (see, page 121 of Concentric's evidence in EB-2022-0200, where we stated "[g]iven the risk factors noted above, we ***conservatively*** recommend that Enbridge Gas' authorized equity thickness fall within the range of 40% to 45%."

In this generic proceeding, where the OEB is evaluating equity thicknesses for all industry segments, the floor and ceiling concepts discussed above are now being considered in a comprehensive process by the Board. With regard to equity thickness, Concentric's primary finding within the context of this generic cost of capital proceeding is that Ontario equity ratios across all industry segments are lower than North American industry peers and fail to meet the comparable return standard component of the Fair Return Standard. While we continue to support the use of equity thickness to distinguish risk profiles among Ontario utilities, we have not recommended individual changes to each utility's equity thickness. Rather, we recommend that the deemed equity ratio be set at a minimum of 45.0% for all Ontario utilities, but that each utility have the option to retain its current equity ratio and/or propose differences from the "generic" equity thickness in its rates application. Concentric's recommendation of a minimum equity thickness of 45.0% reflects approximately the midpoint between the current deemed equity ratios in Ontario, which are generally consistent with the Canadian average deemed equity ratio for investor-owned utilities, and the authorized equity ratios for U.S. electric and gas utilities.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

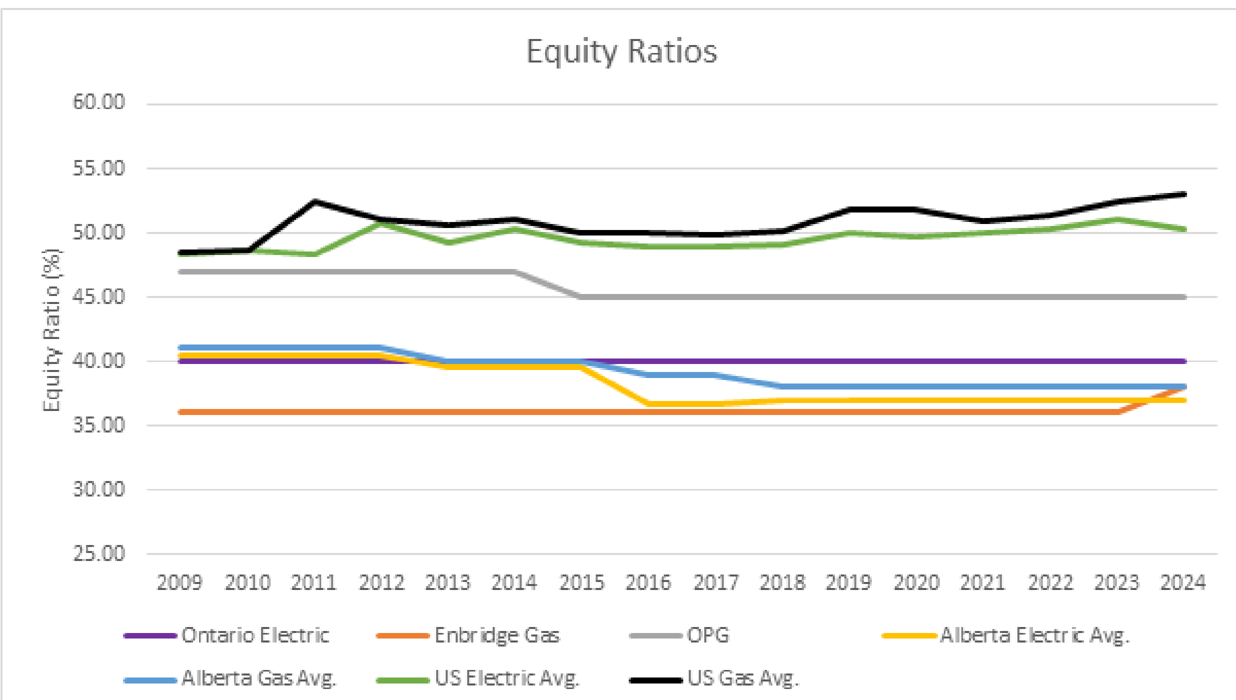
[M2, p.135]

Question(s):

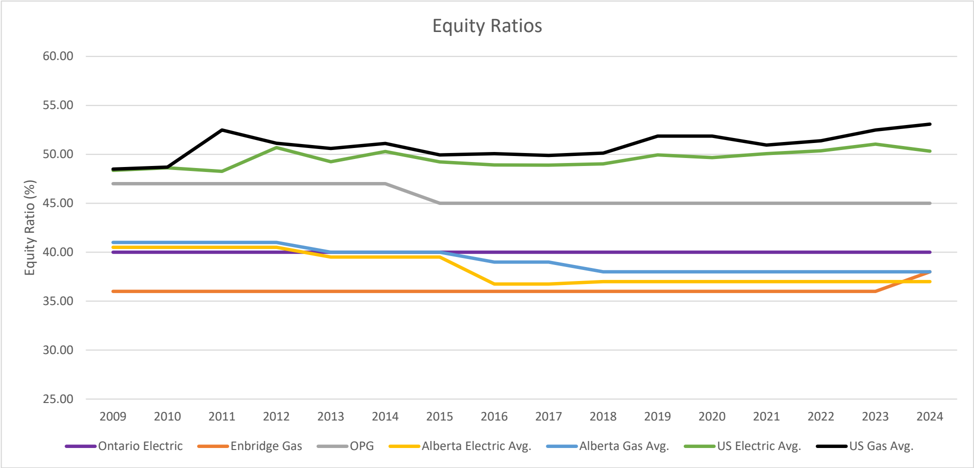
Please provide a revised version of Figure 35 that shows Alberta deemed equity ratio.

Response:

Please see the revised version of Figure 35 and N-M2-12-SEC-54, Attachment 1 for additional data.



	Ontario Electric	Enbridge Gas	OPG	Alberta Electric Avg.	Alberta Gas Avg.	US Electric Avg.	US Gas Avg.
2009	40.00	36.00	47.00	40.50	41.00	48.36	48.49
2010	40.00	36.00	47.00	40.50	41.00	48.63	48.70
2011	40.00	36.00	47.00	40.50	41.00	48.26	52.49
2012	40.00	36.00	47.00	40.50	41.00	50.69	51.13
2013	40.00	36.00	47.00	39.50	40.00	49.25	50.60
2014	40.00	36.00	47.00	39.50	40.00	50.28	51.11
2015	40.00	36.00	45.00	39.50	40.00	49.23	49.93
2016	40.00	36.00	45.00	36.75	39.00	48.91	50.06
2017	40.00	36.00	45.00	36.75	39.00	48.90	49.88
2018	40.00	36.00	45.00	37.00	38.00	49.02	50.12
2019	40.00	36.00	45.00	37.00	38.00	49.94	51.86
2020	40.00	36.00	45.00	37.00	38.00	49.67	51.87
2021	40.00	36.00	45.00	37.00	38.00	50.06	50.94
2022	40.00	36.00	45.00	37.00	38.00	50.36	51.38
2023	40.00	36.00	45.00	37.00	38.00	51.04	52.49
2024	40.00	38.00	45.00	37.00	38.00	50.32	53.08



Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.140]

Question(s):

Concentric states: “As a practical matter, independently developed transmission projects require 100 percent equity during the early stages of development and shift to a mix of equity and debt financing as the project matures into construction through commercial operation.” Please confirm that the underlying equity funding is almost always provided by an affiliate company, often funded by debt financing.

Response:

Across North American transmission projects, Concentric has not exhaustively studied the financing structures to confirm the underlying equity funding is “almost always” provided by an affiliate company, often funded by debt financing. In any event, as described in Concentric’s report, Exhibit M2, at page 18, in Concentric’s view, it is consistent with both financial theory and regulatory practice to determine the cost of capital based on the use of funds and not the source of funds when determining just and reasonable rates.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.13]

Question(s):

Concentric states: "Concentric believes it would be appropriate for changes in the cost of capital parameters and/or capital structure arising from this proceeding to be implemented in the next rate year, including for utilities in an approved rate term, subject to any settlement agreements and each utility submitting a compliance filing demonstrating how the change will be implemented within the context of its specific IR plan (e.g., Custom IR or I-X plan).":

a) Please explain, using an illustrative example, how Concentric proposes that a utility on IRM would implement a change in the cost of capital parameters and capital structure in advance of rebasing.

b) For each of the CLD+ members currently under a Custom IR plan, please provide its position on the ability under its approved framework to have its cost of capital parameters adjusted before rebasing.

Response:

a) Concentric provides the following response:
The implementation of a change in the cost of capital parameters would be established per a compliance filing. As demonstrated in response to the company responses in (b) below, each Company would need to interpret the Board's decision, any limitations under its current rate plan, and reflect any proposed changes in its cost of capital parameters in a responsive filing. The form of that filing may be subject to guidance and approval by the OEB.

b)

Enbridge Gas Inc.:

EGI's proposes that implementation during the midst of a Price Cap IR plan would occur as follows:
EGI proposes that implementation during the midst of a Price Cap IR plan would occur as follows:

- Implementation would be made via a base rate adjustment.
- The base rate adjustment would be subject to price cap escalation (i.e., it would be made prior to the application of price cap escalation in the year of implementation, and would be inherent in amounts (i.e., the base) subject to escalation in subsequent years of the price cap term), consistent with the escalation applied to base year approved cost of capital amounts.
- The base rate adjustment would be calculated leveraging the rate base and capital structure that was approved as part of the cost of service/base year for the price cap term (i.e., the cost of capital revenue requirement impact would be calculated by applying the updated cost of capital parameters approved through the generic proceeding to the base year approved rate base, inclusive of income tax impacts related to the return on equity (i.e., the grossed-up ROE amount), and then subtracting the current approved base cost of capital amount, inclusive of income tax impacts related to the return on equity).

Toronto Hydro:

Toronto Hydro's 2025-2029 CIR Application, as proposed, could incorporate amended cost of capital parameters for equity thickness, rate of return on equity, long-term debt, and short-term debt, subject to an ongoing settlement process.

The OEA notes that "how" these parameters that can be updated within CIR frameworks can be updated within those frameworks will be framework-specific. The OEB should receive specific proposals in that regard once a determination is made as to whether the parameters will be updated prior to the next rebasing.

UCT 2:

Under a Revenue Cap Incentive Rate Making ("IRM") methodology that is approved for a minimum of 5 years, the initial approved revenue requirement takes into account then prevailing cost of capital parameters, including debt/equity ratios, cost of debt and return on equity components. Under UCT2's currently approved methodology (EB-2020-0150) the debt/equity and return on equity components are, effectively, fixed – which is to say, these components do not change year over year when establishing the new rates revenue requirement in the subsequent annual period of the approved IRM term. Deferral and variance accounts can and have been established to capture uncertainties with actual debt costs. For example, in the circumstances of UCT 2 and its initial IRM Term, actual debt costs were not known with certainty and only became certain during the initial IRM Term. The Board's practice has been to allow a regulated utility to recover its actual incurred cost of debt and, again, this principle can be achieved through the use of deferral and variance accounts. The Board has also made determinations where its approved ROE has been "locked-in" and used for purposes of calculating earning sharing mechanisms ("ESM") and used throughout the full IRM Term. For example, this approach was adopted with UCT 2 in the Board's EB-2020-0150 Decision (see page 17 of the Decision at PDF Page 19/50). The impact of this approach has had adverse consequences to the regulated utility when historically low rates of return on equity were experienced and these rates have continued to have application throughout the IRM Term and where approved ROE rates established using the generic cost of capital formula have in any event produced higher ROE levels that would (had they be incorporated into ESM mechanisms) resulted in a lower rate of sharing and under an assumption that bandwidths for the sharing mechanism are held constant.

UCT 2 understands that while it may be possible for a utility to request changes to an approved incentive rate making methodology, such circumstances are limited. Applications of this sort would likely be tested against the Board's well understood policies as set out in its Renewed Regulatory Framework Report (October 18, 2012) and that often underscore IRM decisions that are intended to decouple the price signal from the costs that a utility incurs for the services it provides (Report of the Board: A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach, October 18, 2012, p. 11).

Hydro Ottawa:

Hydro Ottawa's position is that any change to the capital structure and return on equity will be considered in Hydro Ottawa's next rebasing application. Hydro Ottawa's approved 2021-2025 Custom rate plan is inclusive of the approach to cost of capital which is set for the 5 years. Within the Approved Settlement Agreement the parties agreed that Hydro Ottawa's approved ROE embedded in rates for the three years beginning in 2021 and ending in 2023 will be the ROE established by the OEB in the aforementioned 2021 Cost of Capital Parameters update expected in the Fall of 2020. For 2024 and 2025, Hydro Ottawa will update its ROE using the applicable ROE value established by the OEB in the Fall of 2023 for January 1, 2024 rates. Furthermore, the Parties agree that, if the OEB revises its underlying methodology for calculating ROE in advance of Hydro Ottawa's scheduled adjustment for 2024 and 2025, then the updated ROE for 2024 and 2025 will be the lower of the following: (i) the ROE rate established by the OEB for 2024, based upon the revised methodology; or (ii) the ROE rate

calculated for 2024 in September 2023 using the OEB's current formulaic methodology for updating the deemed ROE, as determined in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009 (Appendix B)."
As per the Settlement agreement Hydro Ottawa's ROE was adjusted effective the 2024 year for 2024 and 2025 prior to the OEB revising its underlying methodology for calculating ROE. It is Hydro Ottawa's position that any revised ROE or other cost of capital parameter would be considered after the 2025 year, during Hydro Ottawa's next rebasing application.

Hydro One

As described in the referenced passage of the Concentric report, the decision in Hydro One Networks Inc.'s Transmission and Distribution Rates application (EB-2021-0110) was subject to a settlement agreement. In it, the cost of capital parameters were set for the 2023-2027 rate period and will not be adjusted before rebasing.

OPG

Refer to M2-10-OEB Staff-10.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

If Concentric's recommendations for capital structure and ROE were implemented for the 2025 rate year, for each of the CLD+ utilities, please provide an estimate in the increase of costs that would be recovered from customers.

Response:

The CLD Utilities have provided estimates using their most recently approved ROE and in most cases 2023 approved rate base. As Hydro Ottawa's ROE was most recently approved in 2024, the 2024 rate base was used. UCT2 utilizes a forecast 2025 rate base.

Toronto Hydro:

Using Toronto Hydro's 2023 approved rate base of $ 5,176.8M, the revenue requirement impact of adopting Concentric's recommendation for equity thickness (45% from 40%) and ROE (10% from the 2023 OEB-approved ROE of 9.36%) would be an increase of approximately $43.6M. The revenue requirement impact would be an increase in return on equity of $39.1M, the associated tax gross up of $14.1M, offset by a reduction in interest expense of $9.6M.

Enbridge Gas Inc.:

Leveraging EGI's 2023 actual rate base of $15,858.9 million to calculate cost of capital impacts, the revenue requirement impact of transitioning to an equity thickness of 45% (from 38% as was approved commencing in 2024 in EB-2022-0200) and an ROE of 10% (versus the current 2024 Board formula ROE of 9.21%) would be approximately $160 million. The revenue requirement impact would be comprised of an increase in return on equity of $159 million, plus the associated gross-up for income taxes of $57M, offset by a reduction in interest expense of $56 million.

<u>UCT 2:</u>

Utilizing the recommendations for capital structure and ROE, UCT 2's estimated increase in its revenue requirement is $8,005,220 (utilizing a forecast 2025 rate base and an increase in the ROE from the current 8.34% to 10%). However, this increase does not include any amount of additional risk premium that may be applied for and approved by the OEB under Concentric's proposal.

<u>OPG:</u>

Concentric has not recommended an ROE applicable to OPG in its report and has recommended that should OPG bring forward a proposal and evidence in its payment amounts application regarding whether and what amount of additional risk premium should be applied as part of its authorized ROE and that the OEB consider that proposal as part of that proceeding. Concentric also notes that OPG's current payment amounts are subject to the settlement agreement as part of its EB-2020-0290 proceeding, and its payment amounts should not be adjusted in the interim.

<u>Alectra</u>:

Using Alectra Utilities' 2023 actual rate base of $3,629.1 million to calculate cost of capital impacts, the revenue requirement impact of transitioning to an equity thickness of 45% and an ROE of 10% (increased from the current 8.95% weighted average across rate zones) would be approximately $39 million. The revenue requirement impact would be comprised of an increase in return on equity of $33 million, plus the associated gross-up for income taxes of $12M, offset by a reduction in interest expense of $6 million.

<u>Hydro One:</u>

Using Hydro One's OEB-approved rate base in 2023 of $23.99B, the revenue requirement impact of adopting Concentric's recommendation for equity thickness (45% from 40%) and ROE (10.0% from the 2023 OEB-approved ROE of 9.36%), would be an increase of approximately $194 million. This includes an increase in return on equity of $181 million, the associated gross-up for income taxes of $65, offset by a reduction in interest expense of $52 million.

<u>Hydro Ottawa:</u>

As part of Hydro Ottawa's 2024 annual update application the ROE parameter was updated. Using Hydro Ottawa's 2024 approved rate base and using the Concentric's recommended 10% return on equity (increase from the current 9.21% in rates), and using 45% equity thickness, the revenue requirement impact would be approximately $$12.7M. This includes an increase in return on equity of $11.2M, offset by a reduction in interest expense of $2.3M, plus a gross up Pils amount of $4.0M and offset Capital Stretch Factor impact of $0.2M.

<u>Elexicon</u>:

Using Elexicon's 2023 actual rate base of $473.8M, the revenue requirement impact of adopting Concentric's recommendation for equity thickness (from 40% to 45%) and ROE (10% from the current OEB-approved ROE of 9.43% underpinning Elexicon's rates) would be an increase of approximately $3.6M. The revenue requirement impact would be an increase in return on equity of $3.5M, the associated tax gross up of $1.2M, offset by a reduction of $1.1M in interest expense.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[EB-2022-0200, Exhibit 2, Tab 4, Schedule 1, p.7]

Question(s):

Please confirm that in EB-2022-0200, the OEB approved Enbridge's harmonized accounting policy in which the company proposed Interest During Construction at the OEB's prescribed interest rate for CWIP, as opposed to any other method include the historic Enbridge Gas Distribution approach of using the weighted average cost of debt (WACD)

Response:

Confirmed.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Reference:

[M2, p.153]

Question(s):

Concentric recommends that "the Board apply the WACC to DVA balances that are to remain on utilities' balance sheets for more than one year and retain a short-term rate for DVAs that are cleared within one year." SEC seeks to understand how the one-year threshold would be measured.

a) As an illustrative example, if an amount is recorded in a DVA on September 1, 2024, when would the OEB need to clear the balance for the amount to attract the short-term debt rate?

b) How does Concentric's approach work, considering the OEB's policy for DVA accounts are generally not disposed of until after amounts are audited which results in a lag of at least one year (i.e. normally would not be recovered until January 1, 2027?

c) Does Concentric mean that the shorter-term rate is applied for DVAs cleared within one year or cleared and recovered within one year?

d) Does Concentric propose that this approach be applied to both Group 1 and Group 2 DVAs.

Response:

a) Please see the response to N-M2-21-OEB Staff-27.

b) Please see the response to N-M2-21-OEB Staff-27.

c) Please see the response to N-M2-21-OEB Staff-27.

d) Please see the response to N-M2-21-OEB Staff-27.

Ontario Energy Association (OEA)

Answer to Interrogatory from
School Energy Coalition (SEC)

INTERROGATORY

Question(s):

Concentric proposes that DVA balances (on a utility's balance sheet for more than one year) and CWIP attract WACC. Is the WACC the utility specific WACC included in base rates, or the WACC in a given year based on the OEB's annual cost of capital parameters.

Response:

Please see the response to N-M2-21-OEB Staff-27(e).