YUKON UTILITIES BOARD

IN THE MATTER OF the Public Utilities Act, R.S.Y. 2002, c. 186;

AND IN THE MATTER OF the ATCO Electric Yukon 2023-2024 General Rate Application.

BOOK OF AUTHORITIES TO THE FINAL ARGUMENT OF ATCO ELECTRIC YUKON

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1.	*Re Canadian Western Natural Gas Company Limited Request to Withdraw the 1999 General Rate Application and Assessment of the Need for a 2000 General Rate Application*, EUB Decision 2000-82 (21 Dec 2000)
2.	Board Order 2014-06, Appendix A – Reasons for Decision
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4.	*Independent Power Production and Micro-Generation Regulation*, YOIC 2019/25
5.	Government of Yukon, Yukon's Independent Power Production Policy, Updated October 2018
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7.	Board Order 2009-02, Appendix A – Reasons for Decision
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TAB 1

ALBERTA ENERGY AND UTILITIES BOARD
Calgary Alberta

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED	**Decision 2000-82**
REQUEST TO WITHDRAW THE	**Application 990208**
1999 GENERAL RATE APPLICATION, and	**File 1305-5**
ASSESSMENT OF THE NEED FOR A 2000	
GENERAL RATE APPLICATION	

1.0 INTRODUCTION

The Alberta Energy and Utilities Board (the Board) received correspondence from ATCO Gas and Pipelines Ltd. (ATCO or the Company), dated September 11, 2000, confirming the Company's request of May 4, 2000 to withdraw the Canadian Western Natural Gas Company Limited (CWNG) 1999 General Rate Application (GRA).[1] The 1999 GRA, originally filed with the Board on May 3, 1999, has been held in abeyance for the majority of the time that has passed since the filing date.

A process was established by the Board to consider submissions regarding the Company's request to withdraw the 1999 GRA. The Board also requested submissions as to whether it should direct CWNG to file a 2000 GRA in addition to or in substitution for the 1999 GRA. The Board advised that in the event it determined that some process should be undertaken for either or both the 1999 and 2000 test years, it would consider whether an alternative to a full GRA would be appropriate for either or both of those years. The Board requested submissions as to whether alternative or abbreviated proceedings might be appropriate for 1999 and 2000. As examples, the Board indicated that it could consider the merits of a proceeding dealing with treatment of affiliated transactions during 1999/2000, or of a proceeding dealing with the determination of 1999/2000 refunds based on 1998 rates.

The Company's submission on September 11, 2000 was filed in support of its application to withdraw the 1999 GRA, and in opposition to the request for a 2000 GRA. Responses to the Company's submission were received from the following interveners: City of Calgary (Calgary), Consumer's Coalition of Alberta (CCA), Federation of Alberta Gas Co-ops Ltd. and Gas Alberta Inc. (FGA), Municipal Intervenors (MI), and Public Institutional Consumers of Alberta (PICA). The Company's reply submission was received on September 25, 2000.

2.0 BACKGROUND

The 1999 GRA filed by CWNG forecast a 1999 revenue surplus of $0.5 million based on rates in place at that time. The Company noted in the GRA that such a surplus would not normally have triggered a GRA. Rather, the Company filed the application in recognition of the need for a review of the negotiated Industrial/Producer Settlement, to address the outcome of further ATCO

[1] Canadian Western Natural Gas Company Ltd. changed its name to ATCO Gas and Pipelines Ltd. in December 1999

corporate restructuring, and to address concerns that may have arisen related to two new affiliates, ATCO I-Tek (I-Tek) and ATCO Singlepoint (Singlepoint).

The Board established a process with respect to the 1999 GRA, and a hearing was scheduled to commence in November of 1999. However, on August 17, 1999 the Board advised the Company and interveners that the 1999 GRA was to be held in abeyance until decisions were released by the Board concerning the CWNG 1997/98 Phase 1 and the CWNG 1998 Phase 2. The Board's decision to hold the 1999 GRA in abeyance was made in light of recommendations that arose at the CWNG 1998 Phase 2 hearing.

The Company advised the Board on January 14, 2000 that CWNG and its customers were attempting to institute a settlement process with respect to the issues surrounding the 1999 GRA. On February 8, 2000, Calgary provided a summary of issues and concerns that interested parties had with the proposed CWNG 1999 GRA Negotiation Schedule. The Company replied on February 14, 2000 indicating its preference that the Board issue a hearing schedule for the 1999 GRA as soon as possible after the issuance of the CWNG 1997/98 Phase 1 decision. The Board reestablished the schedule for the 1999 GRA on March 16, 2000 following the release of the CWNG 1997/98 Phase 1 decision.[2] At that time, the Board indicated that it intended to review only 1999, despite a request by interveners to broaden the review to 2000.

By letter dated May 4, 2000, the Company subsequently advised the Board of the Company's request to withdraw the 1999 GRA. The Company summarized its reasons in support of the requested withdrawal, and stated its belief that the 1998 approved rates were appropriate to be applied to customer billings for 1999 and 2000. By letter dated May 11, 2000, the Board rescinded the hearing schedule for the 1999 GRA and provided an opportunity for interveners to comment on the Company's May 4, 2000 withdrawal request. Comments were received prior to the Board's May 11, 2000 letter from Calgary and the MI, and subsequently from the CCA, FGA, PICA and Pan-Alberta Gas Ltd.

While the approach and content of intervener responses varied somewhat, there was general agreement either that the Company should not be permitted to withdraw the 1999 GRA unilaterally, or that conditions should be attached to the withdrawal.

The Board was concurrently notified, by letters dated May 12, 2000 and May 15, 2000, respectively, from ATCO and Calgary that discussions between the Company and interveners were ongoing. Parties requested that the Board again hold the application in abeyance, noting that a self-imposed deadline of June 30, 2000 had been set for the discussions. However, when the June 30, 2000 deadline was not met the Board was asked to provide additional time for the discussions and exchange of data.

Finally, by letter dated August 15, 2000, Calgary advised the Board that the parties were not able to reach an agreement with respect to the 1999 GRA and other matters at issue. The Board was asked to re-establish a schedule to deal with the Company's request to withdraw the 1999 GRA. The process established by the Board was as described in the Introduction to this Decision.

[2] Decision 2000-9

3.0 WITHDRAWAL OF AN APPLICATION: GENERAL PRINCIPLES

The Board noted in its August 28, 2000 letter to parties that the existing legislation under which the EUB operates does not expressly address the right of an applicant to withdraw an application. The Board also noted the decision in *Re Carfrae Estates Ltd. and Stavert*[3], whereby the Ontario Divisional Court (Ontario Court) held that whether or not a unilateral right to withdraw an application exists depends on the particular statutory regime under consideration. The Board invited submissions on this matter and requested that parties address in their submissions whether the Board's governing legislation, in light of the considerations expressed in the *Carfrae* decision, permitted the Company to withdraw the 1999 GRA unilaterally.

Position of CWNG

The Company noted that neither the *Gas Utilities Act* (GU Act) nor the *Public Utilities Board Act* (PUB Act) provide express direction regarding the withdrawal of a GRA. Rather, the Company stated that the legislation focused upon the considerations the Board must apply in arriving at any conclusions regarding rates. The Company also noted that the legislation contains no provision requiring the Board to convene an oral public hearing upon the demand of an interested party.

The Company referred to a number of provisions of the GU Act. The Company noted that section 16 gives the Board the power to take various actions when it has reason to believe that the tolls demanded by the owner of a gas utility "exceed what is just and reasonable". Section 22 gives the Board general supervisory powers over gas utilities and allows the Board to make any order "necessary for the convenience of the public". Section 25 prohibits an owner of a gas utility from charging rates or operating the utility in a manner that is unjust, unreasonable, discriminatory or unduly preferential. Section 34 requires the Board to review the affairs, earnings and accounts of every gas utility at least once every three years (Statutory Review).[4]

Based on these provisions, the Company submitted that the issue the Board must determine is whether the withdrawal of the 1999 GRA would result in rates that are consistent with the public interest, and are just and reasonable. The Company stated that the same standard should apply to the Board's review of the interveners' request for a 2000 GRA.

The Company suggested that the above standard of review was supported by the *Carfrae* decision. The Company noted that the Ontario Court had determined that unilateral withdrawal of a rent review application was not permissible. Rather the Court had found that the application could only be withdrawn if the rent review officer determined that withdrawal was appropriate "having learned the circumstances and in the light of fairness and possible prejudice not only to the parties but to the others who might be affected".[5] The Company suggested that the *Carfrae* case appeared to stand for the proposition that a regulator may permit the withdrawal of a rate application provided it considered all the circumstances, including the impacts upon all stakeholders (including the applicant). The Company submitted that the Board would be acting within its authority if it were to endorse existing rates, in light of the proposed withdrawal of the 1999 GRA, provided it considered the impacts upon the broad public interest.

[3] (1977) 13 O.R. (2d) 537 (*Carfrae*).
[4] The Company noted that parallel provisions are found in the PUB Act relating to public utilities in general.
[5] *Carfrae*, at 545.

The Company submitted that the Board's approval of the withdrawal of the 1999 GRA, and the Board's denial of the request for a 2000 GRA, were both consistent with the public interest and with just and reasonable rate making.

Position of the Interveners

Calgary also noted that both the GU Act and the PUB Act are silent as to whether a party has a right to withdraw an application once submitted to the Board. Calgary argued that, given the issuance of a Notice of Hearing, it had clearly been made to appear to the Board that there was reason to believe that investigation of 1999 rates was warranted. Calgary argued that once the application had been made, the Board acquired an interest in how the matter proceeds and that it was taken out of the hands of the applicant.

Calgary noted an analogy with civil court processes, where a point is reached in the litigation beyond which the plaintiff cannot withdraw its claim without the consent of the defendant or the approval of the court.

Referring to *Carfrae*,[6] Calgary submitted that a similar principle applies in administrative proceedings. In Calgary's view, the principle emerging from this decision is that in the absence of express language permitting withdrawal, where parties could suffer real prejudice as a result of withdrawal, unilateral withdrawal should not be permitted. Calgary submitted that the language of section 16 of the GU Act and section 72 of the PUB Act supports this view.

With respect to the 1999 GRA, Calgary argued that allowing the withdrawal of the application created a real prospect of prejudice to interveners. Calgary noted that interveners who were concerned that rates approved for 1997/1998 were no longer just and reasonable could have applied to the Board pursuant to section 16 for an investigation into the Company's 1999 rates for. If the Company were allowed to withdraw the 1999 GRA, Calgary submitted that these interveners would now be precluded from filing an application to review 1999 rates. Calgary added that parties may also have developed strategies and positions for the 1998 GRA and other proceedings based on the knowledge that there would be a 1999 GRA.

Calgary submitted that the application to withdraw should meet the test of section 16 of the GU Act. Calgary characterized that test as requiring the applicant seeking withdrawal to satisfy the Board that the investigation is not necessary and that the rates to be utilized are just and reasonable. In this instance, Calgary submitted that the Board must ensure that it has proper grounds for allowing withdrawal of an application in the face of potential prejudice to other interested parties.

Based on the decision of the Alberta Court of Appeal in *Coseka Resources Ltd. v. Saratoga Processing Co.*,[7] Calgary submitted that the Board must consider and rule on the justness and reasonableness of the rates which customers will pay, should the withdrawal be granted.

Calgary submitted that "an applicant who desires to withdraw must place all of the facts of his particular case before" the tribunal.[8] Calgary argued that the Company in this case had provided

[6] Which Calgary noted to have been recently cited with approval by the Ontario Divisional Court in *Blackwood v. 736923 Ontario Ltd.* [1998] O.J. No. 2480.
[7] [1981] A.J. No. 579.
[8] Quoting from *Malahide Developments Ltd. v. Fillmore* [1976] O.J. No. 1006, para. 6 (Ont. Div.Ct.).

no evidence that withdrawing its 1999 GRA would result in just and reasonable rates. As a result, neither the Board nor interveners had been provided with an opportunity to examine or test any such evidence.

Calgary urged upon the Board four principles that it believed should be applied to the Board's decision in this matter:

1. Because of the closeness of the administrative process of the Board in rate setting to the judicial process, procedural protections closer to the trial model are required by the duty of fairness.

2. Greater procedural protections are required when the decision is determinative of the issue and further requests cannot be submitted.

3. The more important the decision to the lives of those affected by it, the more stringent the procedural protections that must be mandated.

4. The legitimate expectations of parties that the 1999 GRA would be held, as evidenced by the sequence of events beginning in August 1998, would not be met if withdrawal of the application was permitted.

PICA agreed with Calgary that the Company had failed to provide any evidence to support its contention that the current rates were just and reasonable. PICA cited the original filing of the GRA, the ongoing negotiations, and continuing consumer concern over 1999 and 2000 as indicative of a need for review. PICA also agreed that allowing the Company to withdraw the 1999 GRA would prejudice customers who would now be precluded from seeking an investigation into 1999 rates.

The FGA noted four similarities between this case and *Carfrae*:

1. When the Board's governing legislation is considered as a whole, the overriding rationale is clearly the protection of the public interest and not merely to decide (or not) at the insistence of public utilities.

2. The Board's governing legislation provides it with broad discretion to deal with the subject matter entrusted to it, including the manner in which proceedings are conducted. This factor suggested that the Board acquired an interest in the proceeding once an application was filed.

3. There was no provision in the governing legislation providing for notification of the withdrawal of an application.

4. Allowing the unilateral withdrawal of an application had the potential to prejudice parties other than the applicant, as they would have no recourse to examine 1999.

The FGA concluded that the Company had no unilateral right to withdraw its application, and further that the Board should not consent to such a withdrawal.

The MI suggested that the Board might find some guidance with regard to procedure by referring to the scope and intent of the GU Act and the PUB Act. The MI noted the Supreme Court of Canada's finding that the "Board [has] a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the Public Utilities". The MI submitted that the Board should render decisions on the basis of evidence and information from various parties in order to ensure that the public interest was addressed. The MI also submitted that to permit the Company to unilaterally withdraw its 1999 GRA would be an abdication of the Board's duty to canvas and address all relevant issues in the public interest.

The MI stated that as a result of the Board's public interest mandate, the Board assumed the duty to become involved and interested in an application. The MI argued that, as in *Carfrae*, the absence of a provision for providing notice of a withdrawal implied that a withdrawal application would have to be made before the tribunal at a hearing.

The CCA argued that the Company should not be allowed to unilaterally withdraw its application and that the application should not be allowed to be withdrawn in any event.

Board Findings

(a) Unilateral Withdrawal

First, the Board notes that the Company appears to concede in its submission that it does not have the unilateral right to withdraw the 1999 GRA. Instead, the Company has focussed its submission on the factors that it believes the Board should take into account in deciding whether to allow the GRA to be withdrawn. Second, the Board notes the general agreement among all parties, including the Company, with the approach to withdrawal taken by the Ontario Court in *Carfrae*.

The Board has not previously been asked to consider whether applicants to it have a unilateral right to withdraw their applications and, if so, in what circumstances. The Board intends to set out its views on this question, but cautions the parties that this decision applies only to tariff applications under the GU Act. In other circumstances, involving different types of applications under different provisions of its governing legislation, the Board's conclusion might be different. The Board agrees with the parties that the starting point for considering the question of withdrawal of a GRA is the *Carfrae* decision, which was recently approved by the Ontario Court General Division in the *Blackwood* case referred to by Calgary.[9] It was also cited with approval by the Ontario Divisional Court in *Malahide Developments*, also referred to by Calgary.

In the Board's view, *Carfrae* stands for the general principle that, in the absence of an express right to withdraw an application unilaterally, the applicable legislation must be closely examined to determine whether, at some point, the tribunal takes an interest in the subject matter of the application to such an extent that the original applicant loses the right to withdraw unilaterally.

In *Carfrae*, the question was whether a landlord could unilaterally withdraw a rent review application under the Ontario *Residential Premises Rent Review Act*. The Court was primarily influenced by the provisions of the legislation authorizing the rent review officer to add parties

[9] Not noted by Calgary was that on March 24, 1999, the Ontario Court of Appeal refused to grant leave to appeal in the *Blackwood* case: *Blackwood v. 736923 Ontario Ltd.* [1999] O.J. No. 1045 (C.A.).

and issues once the application had been filed. In the Court's view, the discretion of the officer in this respect indicated that the matter before him was *in rem* and not merely *in personam* (i.e. affecting only the original parties to the application).

Another important factor for the Court in *Carfrae* appeared to be the possibility of prejudice to other interested parties if the application could be withdrawn at the instance of the landlord. The Court noted that in the absence of an application by the landlord, tenants had a limited time period within which to commence their own rent review applications. Allowing a landlord to withdraw its application beyond this statutory limitation would prevent tenants from exercising their own right to seek review of rents under the legislation.

The Ontario Court also noted that the legislation did not provide for any notice to be given to parties in the event of unilateral withdrawal of an application, which it considered necessary if unilateral withdrawal were contemplated.

In the case of the 1999 GRA, the Board notes that unilateral withdrawal is not expressly provided for in the GU Act, the PUB Act or the *Alberta Energy and Utilities Board Act*. Neither is provision for notice of withdrawal of an application made in those pieces of legislation or the Board's Rules of Practice.

The rate-setting process has been described as "quasi-legislative" because it establishes general rules (i.e. rates and terms and conditions of service) that apply not only to the parties to an application, but to the public at large who will receive service from the utility. In this sense, the Board considers a GRA, like the rent review application in *Carfrae*, to be an *in rem* matter rather than an *in personam* one. As in *Carfrae*, the issues raised by the GRA extend beyond the parties to the application itself, which include only some representatives of the public affected by any rate application.

As pointed out by the MI, the Board's mandate to "safeguard the public interest in the nature and quality of service provided to the public by the public utilities" is "of the widest possible proportions."[10] Whether or not the owner of a gas utility makes a rate application, the Board has both the duty and the discretion to oversee the rates of the gas utility. This is done to ensure that those rates continue to be just and reasonable, having regard to the nature and quality of service provided by the gas utility. This duty is reflected in both sections 16, 25 and 34 of the GU Act and the parallel provisions of the PUB Act. In particular, section 16 of the GU Act provides for the Board, on its own motion or the application of an interested party, to investigate the rates of a gas utility where it is made to appear to the Board that they are no longer just and reasonable. The Board's discretion to investigate rates and trigger a GRA regardless of the intentions of the applicant or any other party is a strong indicator to the Board that if, in fact, a GRA is filed by the utility, the Board acquires an interest in the application. Therefore, it is effectively taken out of the hands of the utility.

This is particularly so where potential prejudice could accrue, if the application were unilaterally withdrawn, to interested parties other than the applicant. As already noted, an interested party can apply to the Board pursuant to section 16 of the GU Act for an investigation of the rates of the utility. Although no time limitation is set out in section 16, an interested party is effectively

[10] *ATCO Ltd. v. Calgary Power Ltd.* [1982] 2 S.C.R. 557, at 576 (per Estey J.)

limited to applying for an investigation only in the year in respect of which investigation is sought. This limitation arises from the provisions of section 32 of the GU Act, which limit the Board, when considering rates, to the calendar year in which the application is made. In the case of the Company's 1999 GRA, interested parties would effectively be precluded from seeking an investigation into 1999 rates if the 1999 GRA were withdrawn, 1999 having long since ended. Therefore, withdrawal of the 1999 GRA raises a possibility of real prejudice to interested parties.

Having regard to these factors, the Board concludes that where the year to which a rate application relates has passed, the applicant does not have a unilateral right to withdraw its application. Whether the applicant can unilaterally withdraw the application at some point during the test year (when interested parties would not be precluded from making a section 16 application) is a question the Board need not answer in this case.

Therefore, the Board concludes that the Company cannot unilaterally withdraw the 1999 GRA. The question then becomes whether the Board should exercise its discretion to permit the Company to withdraw the GRA and, if so, subject to what conditions.

(b) Board Discretion to Allow Withdrawal of an Application

The parties submitted a number of possible tests and criteria that they believed the Board should apply in deciding whether the Company should be permitted to withdraw the 1999 GRA.

In considering this question, the Board particularly notes that in a non-test year (i.e. a year in which a GRA is not filed by a gas utility), the Board is nevertheless bound to assess the utility's annual Report on Finances and Operations. This assessment considers whether the rates set in the last GRA continue to be just and reasonable. In carrying out this duty, the Board relies on its own expertise to determine whether the utility should be required to submit a new GRA. While the Board does not seek input from interested parties, parties also remain free to apply to the Board for an investigation pursuant to section 16 of the GU Act in a non test-year.

Where the utility has submitted a GRA and then seeks its withdrawal, the Board agrees with Calgary that the test applied by the Board should be consistent with the tests it applies when deciding whether to conduct a full investigation of rates under section 16 of the GU Act or section 72 of the PUB Act. In part, the Board considers this test to be appropriate because it is the inability of interested parties to seek an investigation that creates potential prejudice if the GRA is permitted to be withdrawn.

The Board does not, however, agree with Calgary that the onus is, strictly speaking, on the utility to establish that its rates will continue to be just and reasonable if the application is withdrawn by "placing all of the facts" before the Board. To place such an onus on the utility would, in the Board's view, turn the application for permission to withdraw the GRA into the GRA itself. Nor does the Board consider that the onus now lies upon the utility to establish that no prejudice will occur to any interested party by the withdrawal of the GRA. Rather, the Board considers that it should approach the matter in a fashion similar to that by which it would approach a section 16 application by an interested party.

In Decision E95064, involving an application by the Industrial Power Consumers Association of Alberta (as it was then known) for an investigation of the rates of Alberta Power Limited

pursuant to section 72 of the PUB Act, the Board set out the following general approach to such matters:

> Generally, in proceedings such as this, the Board accepts the proposition advanced by the applicant [IPCAA] and Intervenors that the utility is in the best position to determine the likely results of its operations while the Board and the Intervenors can rely on only that information published or provided by the utility. For that reason, the Board considers that it should not expect an applicant to meet a strict onus of proof in an application requesting the Board to exercise its discretion under either section 72 or section 81 of the PUB Act.
>
> At the same time the Board recognizes that a general rate application or even an inquiry under section 72 will entail a considerable amount of work and effort and expense on the part of all parties. ***The Board will not necessarily exercise its discretion under these sections unless it finds that there is a reasonable expectation that a significant net benefit will accrue to the customers of the utility or to a particular class of customers as a result of an investigation.***[11]

The Board also notes that the Alberta Court of Appeal refused IPCAA's application for leave to appeal this Decision.[12]

The Board also considers this approach to be applicable in a case where a utility applies to withdraw a GRA and interested parties object to the withdrawal. Accordingly, the Board is of the view that it must be satisfied that there is a reasonable expectation that a significant net benefit will accrue to the utility's customers (or a class of those customers) by denying withdrawal and conducting the GRA.

The Board recognizes, as it did in Decision E95064, that much of the information is in the hands of the utility. However, in this case, the Board also has the 1999 GRA, and the results of the Decision 2000-9 against which to assess the claims of both the Company and the interested parties as to the justness and reasonableness of the Company's existing rates as set in the 1997/1998 GRA. The availability of this information is particularly helpful to the Board in applying its expertise and judgement as to whether the rates proposed by the Company for 1999 (i.e. 1998 rates as approved in Decisions 2000-9 and 2000-16) are just and reasonable.

In determining whether there is a reasonable expectation of a significant net benefit to customers from a 1999 GRA, the Board agrees with the Company that the Board must balance the interests of both utility and customers. In this respect, the Board disagrees with those parties who seemed to suggest that the Board should necessarily favour the customer in considering whether to require a full 1999 GRA. The Board considers that whether to allow the Company to withdraw must depend on a number of factors. These include any changes in circumstances since then that may affect the application, along with the nature and magnitude of the potential impacts of withdrawal of the application. The Board does not consider that interested parties have a right to a GRA on request.

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[11] Decision E95064, *Re: Alberta Power Limited*, pp. 9-10 [emphasis added]

[12] *Industrial Power Consumers Association of Alberta v. Alberta (Energy and Utilities Board)* (1996) 184 A.R. 228 (C.A.).

Given the circumstances, several parties also suggested that fairness required a GRA to be held. Calgary, in particular, suggested that, based on the Company's actions in filing the GRA as well as the Board's actions in publishing notice of the GRA and directing that it be refiled, interested parties had a legitimate expectation that a 1999 GRA would be held. Whether or not such a legitimate expectation may have been created in these circumstances (which the Board need not decide for the purposes of this decision), the Board believes that it has discharged its duty of fairness by the process it has followed in this case. Specifically, the Board believes that parties have been given an adequate opportunity to understand the Company's request to withdraw the 1999 GRA and to make submissions to the Board describing their views in relation to that request.

4.0 WITHDRAWAL OF THE 1999 GRA & NEED FOR A 2000 GRA

Having set out the general principles for withdrawal of an application and having concluded that the Company cannot unilaterally withdraw the 1999 GRA, the Board will consider whether the 1999 GRA should be withdrawn and/or whether a 2000 GRA is necessary. In the Board's view, the test is the same in each case. Accordingly, the Board will consider the factors raised by the parties in relation to these two years to determine whether there is a reasonable expectation of a significant net benefit of a GRA in either or both of those years.

Parties generally arranged their submissions around four categories: potential prejudice, prospective rate-making, changed circumstances, and impact on customers. Within each category, while the discussion often related to both 1999 and 2000, the Board is mindful that certain issues pertain specifically to either 1999 or 2000.

4.1 Potential Prejudice

Position of CWNG

The Company argued that interveners' claims of prejudice assumed that, in the absence of the 1999 GRA, the Board would have acceded to interveners' request to conduct a full investigation of the Company's 1999 rates under section 16 of the GU Act. The Company submitted that prejudice could only be determined following a review of evidence available at the material time.

The Company submitted that, based on the evidence before it, the Board could and should determine that the application to 1999 and 2000 of the rates approved in Decisions 2000-9 and 2000-16 for 1997 and 1998 would be in the public interest and consistent with just and reasonable rate making. The Company added that other evidence also showed that its rates were in the public interest, including: the changed circumstances since CWNG filed its 1999 GRA; the 1999 GRA itself; the forthcoming ATCO Group Affiliate Transactions and Code of Conduct hearing (Affiliate Proceeding); and CWNG's stated commitment to file GRAs for 2001/2002.

The Company argued that Calgary could not contend, on the one hand, that a just and reasonable rate determination must be founded on a public review of all GRA related matters and, on the other hand, contend that a piecemeal review was within the Board's jurisdiction. The Company stated that the sufficiency of evidence, the scope and the need for any review were matters within the Board's experience, expertise and discretion. The Company stated that interveners (Calgary

in particular) could not have it both ways. Otherwise, the Board, the Company and Alberta consumers would be held hostage to costly and time-consuming retrospective rate reviews upon demand. The Company also noted the regulatory cost that would arise in connection with the 1999 and 2000 GRAs.

Position of the Interveners

Calgary noted that during the proceeding to approve the merger of the Company and Northwestern Utilities Limited (NUL), the Company submitted that all affiliate transactions would be investigated in the context of its 1999 GRA. The Company subsequently submitted that there should not be a 1999 GRA. Furthermore, Calgary noted the Company's position that affiliate transactions should be reviewed during the Affiliate Proceeding only from January 2001 forwards. In Calgary's view, this course would preclude review of the impact of these transactions during 1999 and 2000.

Calgary estimated a possible impact in excess of $10 million arising from affiliate transactions. Calgary argued that, although the Company opposed a "piecemeal review" of 1999 and 2000 affiliate transactions, other proceedings involving other companies in the ATCO Group would be dealt with in precisely such a fashion.

PICA submitted that allowing the Company to withdraw its application and determining that its current rates were just and reasonable would prejudice the rights of customers whom, but for the filing of the 1999 GRA, would have been entitled to file a complaint with the Board. PICA submitted that withdrawal of the Company's application was not in the public interest, would unduly prejudice the rights of customers, and would likely result in the approval of rates that were neither just nor reasonable.

With respect to affiliate matters, PICA noted that the Affiliate Proceeding related primarily to policy matters rather than cost impacts. The impact of affiliate transactions that commenced in 1999 and 2000 would be compounded over time and not fully recognized in an examination of only 2001 and onwards.

The FGA stated that the intent of the Company's submission was to insulate the impacts of its practical reorganization from review and to ensure that there was no sharing of financial benefits with customers for 1999 and 2000.

The MI submitted that the true issue for the Board was whether withdrawal of the 1999 GRA frustrated the Board's ability to determine whether the prevailing rates would continue to be reasonable in the circumstances of 1999. The MI believed that the unilateral withdrawal of the GRA would, in light of section 32 of the GU Act, also leave interested parties with no recourse to examine revenues and costs during that fiscal year. The MI noted that parties had relied on the filing of the 1999 GRA and the scheduled hearing to ensure that a forum for determination of reasonable rates would be available.

The MI also suggested that in Decision 2000-9, the Board appeared to have taken a position on Carbon and affiliate transactions on the understanding that such issues would be dealt with in the Company's 1999 GRA.

The MI was doubtful that sufficient conditions could be placed upon withdrawal of the 1999 GRA to serve the interests of the Board and interested parties. The MI argued that the Company had not provided any proof that there were no germane issues of public interest in the 1999 fiscal year. The MI believed that, prior to granting a withdrawal of the 1999 GRA, the Board should require the Company to provide satisfactory evidence that issues of interest to the public, the Board, and the intervening parties would be either irrelevant, or of such little significance that they would be offset by the costs associated with a public hearing.

The CCA argued that there were no conditions that would be sufficient to allow the withdrawal of the application while protecting the public interest. The CCA supported the proposal for a combined 1999/2000 hearing put forward by the FGA. The CCA noted the Company's statement that, "the withdrawal of the 1999 GRA does not deprive the Board of the ability to conclude that the rates for 1999 and 2000 are just and reasonable." The CCA suggested, however, that the Company would not feel that it had been treated fairly if the Board found, based on the information at hand, that the rates were not just and reasonable.

Board Findings

The Board finds that, as a result of the 1999 test year being past, there are two countervailing prejudicial impacts that may arise in this case. On the one hand, if the Board does not see fit to continue the 1999 GRA, customers would be precluded from examining 1999 CWNG rates by virtue of the provisions of section 32 of the GU Act, as noted in section 3.0 of this Decision. On the other hand the Company could be subjected to a rate review based on evidence that would not have been available during the test year–i.e. a retrospective rate review.

As was noted in section 3.0 of this Decision, the Board has the discretion to determine if a rate review is required without considering all of the evidence that would normally form the record of a GRA. The Board will look to whether there is a reasonable expectation of a significant net benefit to customers in holding a 1999 GRA. In the course of the Board's ordinary review of utility operations, it has available the results of previous GRA proceedings, the utility's filed actual results for the past year, and general economic indicators and public information, all of which is used to assess whether a utility should file a GRA for the current year. If the Board finds that it has sufficient evidence to determine, to its own satisfaction, that a GRA is not required, the Board does not believe that customers would be treated prejudicially by that finding. The Board notes that a request by an interested party for a GRA in any year does not confer on that party a right to a GRA. The responsibility for that decision rests with the Board. Furthermore, the tests that the Board would apply to such a request to determine whether a GRA was warranted would not differ materially from those applied by the Board in its own review.

In this instance, in order to satisfy the rights of customers to a fair review process, the Board will consider all of the items noted above as part of its ordinary review, as well as particular issues raised by customers in this case. Therefore, while the parties could be prejudiced by a unilateral decision to withdraw the 1999 GRA following the end of 1999, the Board's review process carried out in addition to this decision will ensure that any such potential prejudice is avoided.

With regards to the issue of potential prejudice to the Company, the Board must, in carrying out its duties, also guard the rights of the Company to a fair, prospective rate review. To avoid any retrospective rate enquiry for 1999, the Board will, to the extent possible in the circumstances,

only consider information that would have been available during that year in a normal review process.

For the year 2000, the Board notes that it has available all of the usual information that would be used to determine whether or not there should be a 2000 GRA.

The Board notes parties' submissions that the Company had represented, particularly during the CWNG and NUL merger proceedings, that affiliate transactions would be dealt with at the 1999 GRA and that withdrawal of the GRA would not allow customers to examine these transactions for 1999 and 2000. The Board is of the view that the Affiliate Proceeding, now scheduled, is the proper forum for examination of most of these issues, according to whatever scope is deemed to be appropriate for that proceeding. However, consideration of the impact of affiliate transactions on the 1999 and 2000 CWNG revenue requirements is appropriately part of the Board's deliberations in this Decision.

The Board also notes the MI's position that the Board appeared to signal in Decision 2000-9 that issues surrounding Carbon storage and affiliate transactions would be dealt with in the 1999 GRA. The Board notes that the specific orders in Decision 2000-9 refer to the next CWNG proceeding. Furthermore, the Board is not compelled to continue with the 1999 GRA to deal with affiliate issues alone. Parties have been provided a full opportunity to comment on the need for 1999 and 2000 GRA's for CWNG without limiting the scope of issues the Board would consider, as they pertain to the revenue requirements for those years. The Board considers that that opportunity, in conjunction with the Affiliate Proceeding will provide parties with ample opportunity to address CWNG's affiliate transactions.

4.2 Prospective Rate Making

Position of CWNG

The Company noted that the Board does not normally review the rates charged by a utility on a yearly basis. The Company submitted that such an annual review would be costly, duplicative, and inefficient, and would not enhance the Board's ability to ensure that a utility's rates were just and reasonable. The Company also claimed that annual reviews and the attendant delays would undermine prospective rate making; would delay the finalization of rates, thereby increasing rate uncertainty; and could seriously undermine the benefits of the existing scheme of financial regulation within Alberta. The Company noted that none of the interveners appeared to have acknowledged the prospective rate-making model.

The Company pointed out that if 1999 and 2000 GRAs were conducted CWNG would be subject to five consecutive years of retrospective rate reviews, which the Company believed to be excessive. The Company noted that, if this were to occur, the incentive for utilities to make efficiency gains for the benefit of both ratepayers and shareholders could be adversely affected. There would be, CWNG argued, a clear disincentive to utilities to strive for efficiencies if efficiency gains accrued wholly to ratepayers in consecutive after-the-fact decisions over an extended period.

The Company submitted that many of the areas of its business allegedly requiring review were examples of retrospective rate making that only arose because the test year had already passed.

The Company took exception to the possibility of interveners relying on the knowledge of actual events in 1999 in order to justify a “prospective” rate review for 1999.

The Company did not suggest that the Board would act outside its jurisdiction were it to proceed with either the 1999 and 2000 GRA. However, the Company submitted that to do so would be inconsistent with Alberta’s prospective scheme of regulation.

The Company also rejected the assertion made by interveners that CWNG was responsible for the delay in proceeding with the 1999 GRA and confirmed its willingness to prepare and file a 2001/2002 GRA.

Position of the Interveners

Calgary noted that the Company did not attempt to withdraw its 1999 GRA until May 4, 2000, six days after it had been directed by the Board to re-file the GRA. Calgary argued that if the proceeding had gone according to the Board's revised schedule, it would have already been completed.

With respect to any delay caused by the Board's current schedule, Calgary argued that it would be unfair to remove interveners' ability to test rates because of a government initiative in another regulatory arena. In its view, even if a determination could take two or three years to complete, it would not be justification to shortcut the review of just and reasonable costs.

Citing the Supreme Court of Canada’s decision in *Bell Canada v. CRTC* (1989), Calgary submitted that rendering a decision after the test year has ended need not be considered "after-the-fact" or retroactive rate making. Calgary also noted that there was nothing unusual about a final decision on the Company's rates being issued after the end of the test year.

PICA countered the Company's argument that a delay in the setting of final 1999/2000 rates would be contrary to the interests of the applicant and consumers alike. PICA noted that the final rates for 1997 and 1998 were also not known until well after the fact but were still of value to customers. PICA argued that knowledge of actual rates coming several years after the test period was not a valid reason for avoiding a GRA.

PICA also noted that the 1999 GRA had been the subject of extensive and protracted negotiations. PICA submitted that if the Board allowed the Company to "steam roll" its 1999 and 2000 costs over customers, the Board would effectively dissuade customers from ever participating in negotiations for fear of losing their opportunity to examine rates.

The FGA proposed a combined 1999 and 2000 rate hearing to reintroduce a measure of prospectivity to the proceeding. It was proposed that 1999 actuals and 2000 forecasts be filed. To simplify matters, the FGA further suggested that Board directions from Decisions 2000-9 and 2000-16 not apply to this proceeding.

The MI noted the Company’s argument that if efficiency gains and benefits to shareholders are not meaningful, there was less incentive to achieve them. The MI also noted the Company’s argument that it would be a disincentive to utilities should efficiency gains accrue to ratepayers in consecutive rate decisions over an extended period. The MI submitted, however, that regular reviews of GRAs ensure that progressive improvements in efficiencies are on target.

The MI submitted that a 2000 GRA would not be an adequate or sufficient substitute for a 1999 GRA. However, the 1999 GRA should be extended to include 2000. The MI noted that interested parties have relied on the prospect of a full review of the 1999 issues. Should the Board determine that abbreviated or alternative proceedings are appropriate, the MI submitted that the Board should canvas such a procedure with the Company and interested parties at the outset.

Board Findings

The Board views prospective rate making as a process that is in the interests of both the Company and its customers. When the revenue requirement is set and rates are implemented for a test year, it is expected that they will be in place for some time before the next GRA is required. In the interim, the utility can expect to be able to benefit from efficiency gains it achieves during that period. In this process, the Board acts as a substitute for normal competitive forces. In a competitive environment, gains in revenues due to efficiencies are realized for a short term but are quickly matched by competitors. Once this occurs, the savings from increased efficiencies are transferred to consumers in the form of reduced prices. In a regulated environment, this transfer of savings to consumers occurs following the subsequent GRA and the setting of new rates, which reflect any reductions in the utilities' revenue requirements that arise from its increased efficiency.

Between GRAs, the Board monitors the utility's most recent actual results to determine whether it expects that rates will continue to be just and reasonable for the current fiscal year. If the Board is of the view that customers are likely to significantly benefit from a GRA, it will call for one before the Statutory Review. It follows that, in the year following a GRA, the Board must be convinced that some outside factor would cause the utility to earn more than a reasonable profit without undertaking any efficiency improvements. For example, a dramatic and unexpected reduction in interest rates might lead the Board to find that the utility could benefit from a windfall profit at currently approved rates and order the utility to file a GRA. However, in the absence of such factors, the Board must conclude that the utility has earned its return by improving its operational efficiency, or through increased revenues from its regulated activities.

The Board agrees with the position of interveners that the passage of time does not impede the Board from conducting a review of 1999 rates in this instance. However, the decision whether or not to undertake that review will be based on the standard prescribed in the GU Act, and elaborated upon in Decision E95064. The Board will also consider, following a GRA, the factors described above.

The Board is committed to prospective rate making. Yet, the Board acknowledges a number of situations where test years have been completed to various degrees prior to the hearing being held and/or the related decision being issued. In the Board's view, completing the hearing and decision after the end of the test year are within its power and consistent with the practice of the Board.[13] Notwithstanding those exceptions, the Board makes every effort to preserve the forward test year with decisions that are not retrospective in nature or appearance.

[13] Decisions 2000-9 and 2000-16 pertaining to CWNG for 1997 and 1998 are examples.

The Board notes PICA's comments that permitting withdrawal of the 1999 GRA could hamper future settlement negotiations. The Board will discuss settlement negotiations further in section 5 of this Decision.

4.3 Changed Circumstances

Position of CWNG

The Company submitted that the filing of the 1999 GRA was the result of unique circumstances that existed at the time of filing. The Company noted that it was intended at that time that CWNG and NUL would be merged effective January 1, 1999. The Company stated that it had also sought to finalize the Industrial/Producer Settlement that it had negotiated with customers and that had received interim approval effective February 1, 1999. The Company noted that after filing of the 1999 GRA, the effective date of its proposed corporate restructuring had been moved to January 1, 2001. Similarly, the Board had approved the negotiated Industrial/Producer rates in Decision 2000-16 dated June 13, 2000. The Company argued that by the time it applied to withdraw the 1999 GRA, the circumstances that had led to its filing no longer existed.

The Company also submitted that in light of the Board's extensive review of rates for the 1997 and 1998 periods, and the review that it expected would be conducted with respect to the 2001-2002 test periods, a 2000 GRA would also serve no useful purpose. The Company suggested that the 1997/98 GRA addressed all components of CWNG's rates, including depreciation, operating expenses, rate of return and rate structure and affiliate transactions. The Company submitted that what it perceived as a thorough and recent consideration of the key issues provided a reasonable basis on which the Board could conclude that 1998 rates would continue to be just, reasonable and in the public interest for 1999 and 2000.

With respect to corporate restructuring, the Company submitted that its position was always that a GRA would need to be filed in order to address the implementation of that change. Furthermore, the Company observed that CWNG's pursuit of cost savings and efficiency gains was never expected to be restricted only to restructuring. The Company argued that restructuring efficiencies began before the merger application and continued since. The Company noted that permission to retain efficiency gains was within the Board's discretion, and that interveners were not entitled to them as of right.

Position of the Interveners

Calgary noted that in the 1999 GRA, the Company stated that, with regard to the Industrial/Producer Settlement, "To approve rates on a final basis for 1999, the Board must first approve an appropriate revenue requirement for 1999." Calgary argued that this was still necessary.

With respect to the restructuring of the Company and NUL, Calgary noted that the effective date of this merger was less important than the operational date. Calgary noted evidence that the operational date of this merger had taken place in 1998 and that, consequently, a 1999 GRA was necessary to review the costs and benefits of the merger and their impact on customers.

PICA noted that the Company and NUL had proceeded to conduct business under the new merged structure as though it had already been formally undertaken. As evidence, PICA noted numerous specific agreements from the Affiliate Proceeding.

The MI concurred that changes to revenue and expenses arising from the preparation for reorganization merited investigation and review by the Board.

The CCA noted the confusion that could arise from separating affiliate matters from the remainder of GRA matters. The CCA suggested that affiliate issues be examined on an individual company basis.

Board Findings
The Board notes that the Company filed its 1999 GRA in the midst of considerable regulatory uncertainty. The application itself was somewhat unusual for a GRA. It applied to only one test year and the proposed revenue requirement was very similar to that requested for 1998. If the change in revenue requirement was the only indicator of the need for a GRA, then the Board doubts that the Company would have ever filed the 1999 GRA.

The Board accepts the Company's explanation that some of the circumstances that led to the 1999 GRA no longer exist. The restructuring of the Company and NUL, contemplated for 1999 or 2000, did not transpire as planned. As well, the Board dealt with industrial/producer transportation rates, arising from the Industrial/Producer Settlement, during the CWNG 1998 Phase 2 proceeding. Further, the Board notes that separate proceedings have been initiated on the issues of affiliate transactions and codes of conduct, and pension.

The Board accepts the interveners' argument that the Company began its re-structuring as early as 1998 and has undergone further restructuring during 1999. However, the Board is not convinced that this is reason enough to require a GRA for either 1999 or 2000. As noted in section 4.2, the revenue requirement impact of affiliate transactions will be only one of the matters pertinent to the Board's deliberations.

The Board notes one further change in circumstances, the finalization of 1998 rates. The Board notes that this has enabled the Company to provide the estimated impact on the Company's 1999 and 2000 revenues. That information has been useful to the Board in its annual Report of Finances and Operations for 1999.

Before requiring a GRA, the Board must be convinced that there is a reasonable expectation of a significant net benefit that should accrue to customers. The Board will consider this question further as it addresses the withdrawal of the 1999 GRA, and the assessment of the need for a 2000 GRA.

4.4 Impact on Customers

Position of CWNG
The Company stated that in addition to the delay that would result from proceeding with the 1999 GRA, considerable costs would be incurred. The Company noted the approved cost claims that totaled $3.4 million for CWNG's 1998 regulatory proceedings and a further $0.4 million pursuant to the CWNG/NUL reorganization. Absent compelling reasons for proceeding with the 1999 GRA, the Company submitted it would be contrary to just and reasonable rate making to incur the unnecessary expense and delay associated with a detailed public review in the circumstances.

The Company responded to intervener concerns about affiliate transactions. It noted that the ATCO Group filed its Affiliate Transactions and Code of Conduct application with the Board on July 21, 2000, and that a proceeding was now scheduled. The Company expected that the issues associated with affiliate transactions, including those with Singlepoint and I-Tek, would be reviewed during that proceeding. The Company suggested that the combination of this proceeding and the proceedings that had occurred during 1999 (the CWNG/NUL reorganization, and the 1997/98 CWNG GRA) called into serious question the necessity for another review of affiliate costs relating to 1999 and 2000.

The Company also argued, however, that the Affiliate Proceeding should not be used as a forum to adjust 1999 and 2000 rates. The Company argued that any review and scrutiny of affiliate transactions in that proceeding should be conducted on a prospective basis. The Company stated that it should not be required to have the financial impact of affiliate transactions on 1999 and 2000 rates reviewed as part of the upcoming Affiliate Proceeding. A piecemeal review, isolating a single component such as affiliate transactions, would, in the Company's view, to be contrary to the public interest.

The Company argued that many of the issues raised by interveners were not of sufficient significance to warrant undertaking a GRA for 1999 or 2000. It argued that the impact of many of the issues, including the effect of restructuring, operating and maintenance expense and depreciation, were materially overstated. The Company also noted that interveners did not address other issues that would, in its view, likely lead to an increase in rates, such as inflation and higher equity and debt rates.

Position of the Interveners

Calgary noted that the Company had to be ordered to file a 1998 GRA, and that the Board ultimately awarded a refund of approximately $25 million.

Calgary noted four items that it believed should be addressed in a 1999 GRA. These were:

- The minor change in interest rates for 1999 did not account for the Return on Common Equity requested in the 1999 GRA.

- A 1999 Federal Tax Court decision in *Rainbow Pipeline Company Ltd. vs. Her Majesty the Queen* changed the interpretation of certain deductions available to utilities.

- The actual 1998 operating and maintenance expenses were significantly lower than the 1998 approved amount. The 1999 forecast, in turn, was significantly higher than both the 1998 actual and the 1998 approved amounts.

- The filed 1999 depreciation expenses included the amortization of losses due to the sale of computer equipment to affiliates and the amortization of restructuring costs.

Calgary noted that affiliate transactions might have created other changes to revenue requirements relative to 1999 and/or 2000. Calgary argued that these changes could amount to $10 million. Calgary argued that, with a 1999 GRA, a limited review of 2000 could be sufficient. In absence of a 1999 GRA, a full 2000 GRA would be required.

PICA refuted the Company's argument that a review of 1999 and 2000 "would be costly, duplicative and inefficient". PICA submitted that where circumstances warrant an annual review over an extended period of time, the Board should not be persuaded from fulfilling its mandate. The converse would imply that the Board should "rubber stamp" the utility's rates in the years following a GRA.

PICA supported the position that a 2000 GRA proceeding was warranted and should be conducted along with a 1999 review. PICA noted that, by and large, rate reviews have yielded cost reductions that were far in excess of hearing costs.

The FGA noted that as a result of the restructuring undertaken in 1998 and 1999, the Company's affiliate, NUL, agreed to reduce its revenue requirement annually by $2.8 million. Even this turned out to be insufficient as NUL reported a 1999 normalized return on equity of 14.95%. The FGA submitted that the operating efficiencies for the Company would likely exceed $2.8 million.

The FGA also noted other issues that should be examined in a 1999 hearing:

- Transportation contracts for gas merchants.
- Appropriate equity rate of return.
- Debt costs.

The FGA noted that the costs of the regulatory proceedings were borne by customers. However, it was submitted that the 1997/1998 proceeding resulted in annual savings of $30 million to customers, for a cost of $3.4 million.

The FGA also supported reviewing the 2000 test year along with 1999 because a measure of prospectivity would be added to the proceedings. Further, it argued that adding another test year within one proceeding was almost a no-cost option for all parties and would not add significant complexity or additional effort. The FGA noted that the Company was the only ATCO company involved in the Affiliate Proceeding that had not had fiscal years 1999 and 2000 reviewed.

The MI noted the following items that could reduce the Company's 1999 revenue requirement:

- An updated actuarial study could reduce pension expense.
- Potential for high growth in producer and industrial transportation revenues.
- Affiliate transactions.
- The removal of non-recurring severance costs included in 1998 O&M.
- Net efficiencies resulting from the merger.
- Impact of the *Rainbow Pipeline* decision on taxes.
- Production and gathering sales subsequent to 1998.

The MI agreed with other interveners that the prospect of incurring hearing costs was not a sufficient reason to allow the unilateral withdrawal of the 1999 GRA. However, if the Board granted the withdrawal of the GRA, it should be on the condition that the interested parties

would be compensated for the costs incurred reviewing that application, all at CWNG shareholder expense.

The MI added that, by failing to review the 1999 GRA, the Board would be speculating that the 1999 rates were just and reasonable, notwithstanding the evident changes in such factors as corporate structure, economy, expenses and revenues. The MI submitted that the circumstances in 1999 were significantly different than those in 1998 and that the Board must review the applicability of the existing charges, tolls and rates in those altered circumstances.

Board Findings

In the Board's view, it must consider the likelihood and materiality of alleged customer impacts in determining whether or not 1999 and/or 2000 GRAs are warranted.

As noted in section 4.1, the Board intends to review the need for 1999 and 2000 GRAs based primarily on the evidence that would have been available during each of those years. The Board does note, however, that the effect of the withdrawal of the 1999 GRA would be the effective implementation of 1998 rates for 1999 and 2000 (as has been proposed by the Company). The rates in place for most of that period (January 1, 1999 to August 31, 2000) were those last approved in 1993. The 1993 rates were higher than the rates approved in 1998. The Board finds that it is appropriate to review the need for 1999 and 2000 GRAs taking into account the effect of applying 1998 rates.

In the normal course of carrying out the Board's mandate, Board staff carried out a review of the CWNG 1999 Report on Finances and Operations (1999 Report) to assess whether rates continued to appear to be just and reasonable. The Company provided additional information to the 1999 Report at the request of the Board that indicated the estimated refund to customers that would result if 1998 rates were applied retroactively to January 1, 1999. The additional refund to customers was estimated to be $14.1 million for 1999 and a further $9.6 million for the period from January 1, 2000 to August 31, 2000.

With respect to 1999 the Board is of the view, as discussed in Section 4.2 of this Decision, that gains made by the Company due to efficiency improvements should accrue to the Company should 1999 be considered a non-test year. Therefore, provided that associated costs are also applied in the years in which they were incurred, any gains made by the Company relating to efficiencies could be isolated to that year. The actual net gains would only be apparent in retrospect for that year. The Board's interest in efficiency gains would then be properly focused on the potential future impact on customers.

In considering the potential impacts to customers raised by the interveners, it is clear that at least some of them are directly associated with efficiencies that the Company has achieved through one form or another. As was stated earlier in this decision report, the Board agrees with the Company that customers are not entitled as of right to the efficiencies the Company is able to realize in non-test years. Therefore, the Board does not believe that the Company, in achieving these efficiencies, has necessarily created a significant net benefit that would accrue to customers.

The requests for increased rates cited from the Company's 1999 GRA filing will not be considered. As the withdrawal of the 1999 GRA would, in effect, impose the lower 1998 rates

from January 1, 1999 onwards, the Board considers these requests to be moot. However, other factors cited by interveners that could have been addressed during 1999 will be considered.

For the year 2000, the Company's actual results from 1999, reflecting any efficiencies achieved by the Company, will be considered. In addition, the major factors cited by interveners as potentially affecting the fiscal results will be considered.

Request to Withdraw the 1999 GRA - Conclusion

The Board agrees with the Company that customers are not entitled as of right to the efficiencies the Company is able to realize in non-test years. At the same time, the Board is sensitive to customer suggestions that certain costs may have been lower for 1999 and 2000 than they were for 1998, the last test year. In Decision 2000-9, the Board stated that it does not want to micro-manage the Company's affairs; neither can it neglect its mandate to protect the public interest.

For 1999 the Board is of the view that it must be satisfied that rates in that year would be significantly different if subjected to the full scrutiny of a GRA. Because CWNG rates were examined in detail for the 1998 test year, the Board does not believe that a GRA would be necessary for 1999 without a major change in the external circumstances affecting the Company.

With respect to the arguments that debt and equity rates would have changed for the Company in 1999, the Board is not convinced that the magnitude of those changes would be material. From its own review, the Board notes that the primary economic indicators as noted in the Bank of Canada statistics have not changed significantly since 1998. Inflation has been steady and long-term interest rates have been relatively flat since 1998, if not trending upward. Based on its own expertise in these matters, the Board finds that estimated changes in debt and equity rates would not cause it to open a 1999 GRA.

With respect to the arguments that restructuring and affiliate transactions in 1999 would have materially changed the CWNG revenue requirement for that year, the Board notes that affiliate charges were canvassed extensively during the 1998 GRA. The Board is satisfied that the Company was not able to benefit unduly in 1998 or 1999 from affiliate relationships at the rate levels established in Decision 2000-9. Further, the Board notes that with respect to any transfers of assets between CWNG and any of its affiliates, or any agreements entered into with affiliates, such transfers or agreements could be the subjects of review as part of the Affiliate Proceeding. The Board is not confirming the scope of that proceeding in this Decision, but merely stating that that is the appropriate forum for parties to raise those issues.

With respect to the argument that expected increases in transportation sales would materially affect the 1999 revenue requirement, the Board would not normally convene consecutive GRAs on the basis of an increased sales forecast. As with efficiency gains, it is assumed that the increased level of revenue from transportation customers would be reflected in the next GRA, thereby benefiting customers.

The Board notes that CWNG was directed not to adjust its methods of treating pension expenses and funding during non-test years in Decision 2000-9. Furthermore, pension issues for CWNG, NUL and ATCO Electric Limited are now the subject of a separate proceeding.

The Board notes the *Rainbow Pipeline* decision was rendered in September 1999. However, no party raised this issue with regards to the 1998 test year even though that proceeding was ongoing into 2000. The Board is not sure whether interveners would have raised this issue in 1999. Nonetheless, the Board has examined the impact of this decision on CWNG, as if it were raised in 1999, and finds that its effects would not have been sufficiently material to convince the Board to require a 1999 GRA.

The Board notes the argument of the Company that items where costs would have legitimately increased have not otherwise been raised in argument by interveners. If these had, the Board accepts that they could have further reduced the potential impacts, singularly or collectively, of the issues raised by the various interveners. Further, the Board accepts that the costs of a 1999 GRA proceeding could be significant.

Based on the foregoing, the evidence provided by parties and the Board's own review, it does not appear to the Board that the CWNG rates established following the 1998 GRA would be higher than just and reasonable if applied to fiscal year 1999. The Board does not expect, based on the evidence noted above, that a significant net benefit would accrue to customers were there to be a 1999 GRA proceeding. However, as a check of the reasonableness of this conclusion, the Board considers it appropriate to look to the 1999 CWNG actual results as stated in the 1999 Report.

Absent the request for a 2000 GRA, the Board notes that it would have performed its own assessment based on the 1999 Report, as well as a review of certain economic factors, to determine if a 2000 GRA would be required. The results of the 1999 Report were reviewed by the Board and adjusted for the following major factors:

- Revenues under 1998 rates
- Changes to tax rulings (*Rainbow Pipeline* decision), and
- Changes to capital structure from prior approval

Specifically, the Board adjusted the 1999 actual results to reflect the 1998 final rates as determined in Decision 2000-35. The Board then incorporated the expected tax savings that would arise from the changed interpretation of allowable capital vs. maintenance expenses established by the *Rainbow Pipeline* decision. Finally, the Board adjusted the cost of equity and debt charges using the capital structure approved in Decision 2000-9.

Accounting for these adjustments, the Board found that the actual 1999 rate of return on equity for CWNG was approximately 9.25% and the normalized 1999 rate of return on equity for CWNG was approximately 11%. The Board notes that this 1999 normalized value was within 200 basis points of the allowed rate of return from 1998. This indicates to the Board that there was no windfall in 1999 that arose from affiliate transactions or other factors noted by interveners.

Although this is not the basis for its decision to permit the withdrawal of the 1999 GRA, the Board is of the opinion that this review of CWNG 1999 actual results confirms the reasonableness of that decision. It also provides the Board with a measure of confidence that a sizeable refund could not reasonably be expected, much less one in the magnitude of the $25 to 30 million range alluded to by interveners. The Board notes that the refunds arising from Decision 2000-9, dealing with CWNG's 1997 and 1998 test years, came after a 4-5 year period

without regulatory scrutiny of the Company's affairs. The Board is comfortable that, only one year after completion of a GRA and absent material changes to external factors, no GRA is required for 1999.

Request for a 2000 GRA – Conclusion

As described above, the Board undertook a review of the 1999 Report with a view to determining whether the Company's rates appeared to be just and reasonable. As just noted, the result that the normalized rate of return on equity for CWNG was within 200 basis points of the allowed rate of return for 1998 is significant evidence to the Board that the rates established in 1998 continue to be just and reasonable. The Board also reviewed the major economic indicators as published by the Bank of Canada and, based on its own expertise in these matters, found that there was no material change in those indicators that would cause it to order a 2000 GRA.

Generally speaking, the Board has considered factors similar to those it considered in relation to 1999 and has reached a similar conclusion.

Based on the foregoing, it does not appear to the Board that the rates established following the 1998 GRA would be higher than just and reasonable if applied to fiscal year 2000. Consequently, the Board will not require the Company to file a 2000 GRA.

As a final note, the Board reminds parties that in Decision 2000-9 it directed the Company to file a 2001 GRA. The Company has, in fact, just filed with the Board a GRA covering the 2001 and 2002 test years.

5.0 OTHER MATTERS

The Board is committed to the prospective regulatory process that has been followed in this province for many years. Similarly the Board is supportive of the negotiated settlement process and the types of arrangements that might arise under that process. When parties are unable to reach a negotiated settlement the Board is confident that the traditional regulatory process will ensure that the public interest is upheld and that customers and stakeholders alike are treated fairly.

However, the Board is concerned with the situation that has developed following each of the CWNG 1997/98 and 1999 GRAs and the settlement discussions undertaken in relation to each of them. In both instances the passage of time has left the Board with test years that were complete prior to the initiation of testing of the GRA. The Board's preference is to avoid situations where there is even the appearance of retroactive rate-making.

To address the Board's concerns, the Board expects that, wherever possible, the timing of future settlement discussions must not encumber the Board's prospective process. In the event that settlement discussions do not lead to a negotiated settlement, the Board expects to receive a GRA with sufficient lead-time to allow for the traditional regulatory process to be followed so as to avoid GRAs in relation to completed test years. The Board considers this responsibility to fall on the utility, unless it can be demonstrated that there are extenuating circumstances that prevented the application from being filed in a timely manner. If necessary, of course, the Board will proceed with future applications filed late in a test year or after a test year is completed. The

Board is hopeful, however, that both the utility and customers will be mindful of the Board's desire to preserve the prospective model of regulation in this province.

6.0 ORDER

Having regard to the arguments presented and the considerations set out in this Decision and also having regard to the Board's own knowledge herein, it is hereby ordered that:

1) The Company shall be permitted to withdraw the 1999 GRA

2) The Company is not required to file a 2000 GRA.

3) The Company shall refund 1999 and 2000 amounts to customers arising from the application of 1998 rates for the period of January 1, 1999 to August 31, 2000; a one-time refund totaling $23.7 million. The Company shall file its proposed methodology for effecting the refund not later than January 12, 2001, with a prospective implementation date of February 1, 2001.

Dated in Calgary, Alberta on December 21, 2000.

ALBERTA ENERGY AND UTILITIES BOARD

<original signed by>

B. F. Bietz, Ph.D.
Presiding Member

B.T. McManus, Q.C.
Member

G. J. Miller
Member

TAB 2

Yukon Utilities Board

Board Order 2014-06
Appendix A: Reasons for Decision
April 23, 2014

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1 INTRODUCTION

On May 27, 2013, Yukon Electrical Company Ltd. (YECL, Applicant) filed with the Yukon Utilities Board (Board) an application, pursuant to the *Public Utilities Act* and *Order-in-Council 1995/90*, for approval of its forecast revenue requirements for the 2013 to 2015 inclusive test years, approval of interim retail rates for 2013, approval of the continued use of the deferral accounts listed within the application, approval to discontinue purchasing third party distribution line (property) insurance at the expiry of the insurance policy July 1, 2014, and approval of updated depreciation parameters (Application).

YECL is a private- investor-owned utility serving more than 16,700 customers in 19 communities in Yukon. YECL purchases power from YEC for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno and Ross River. YECL generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Lower Post, Watson Lake and Swift River. Other areas that YECL serve include Canyon Creek, Deep Creek, Takhini River Crossing as well as rural areas surrounding Whitehorse. In addition, the Applicant owns and operates the Fish Lake Hydro plant outside of Whitehorse and maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

YECL is seeking approval of a revenue requirement of $53.679 million for 2013, $57,458 million for 2014 and $59.912 million for 2015.[1] In addition, YECL is seeking approval for the following deferral accounts[2]:

- Whitehorse Copper Tailings;
- Purchased Power Flow Through;
- Diesel Contingency Fund;
- Fuel Price Flow Through;
- Depreciation Parameters;
- Rate of Return on Common Equity; and
- Defined Benefit Pension Plan.

YECL also sought the ability to flow-through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that YECL operates under or that bear on the nature and extent of YECL's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement[3].

The application also sought approval of interim refundable rates effective July 1, 2013 through YECL Rate Adjustment Rider, Rider R. Rider R increases rates for all YECL and YEC retail customer bills excluding Secondary Energy Rate 32. YECL asked that

[1] YECL Application, page 1-5 and Schedule 1.1 before other revenue.
[2] Each deferral account is discussed in subsequent sections of this decision.
[3] YECL Application, page 1-6.

Rider R be set at 6.5 percent. This would collect approximately one-half of the requested rate increase for 2013. The Board approved interim rate adjustments of 6.5 percent for all electrical consumption on or after July 1, 2013 through Board Order 2013-05 issued June 25, 2013.

On June 6, 2013, the Board issued Board Order 2013-02 regarding the Application, in which the Board ordered YECL to publish a Notice of Application for the General Rate Application (GRA) no later than June 12, 2013 in such appropriate local news publications in YECL's service area to provide adequate notice to the public. YECL was also ordered to make the Application and supporting materials available for inspection at its head office at 100–1100 1st Avenue, Whitehorse, Yukon, and to provide a copy of the Application and any supplemental information upon request. Board Order 2013-03 proposed a proceeding schedule, pending ministerial approval, for the Application with a hearing to commence on November 4, 2013.

On June 20, 2013, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to Section 50 of the Act.

The Board, through Board Order 2013-05, issued June 25, 2013, granted intervener status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (Leading Edge or LE)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)
- Town of Watson Lake (WL)

The proceeding schedule was amended August 6, 2013 due to a request for an extension for information responses which was approved through Board Order 2013-06. The amended proceeding schedule did not change the dates for the oral public hearing.

On August 13, 2013, UCG submitted a motion requesting that the Board issue an order requiring YECL to provide adequate responses to certain IRs submitted by UCG identified in the motion. By way of memorandum dated August 14, 2013, the Board invited comments from YECL on the UCG motion and reply comments from UCG. Board Order 2013-07, issued August 28, 2013, provided a ruling on the UCG motion and directed YECL to provide further and better information responses by September 5, 2013. The remainder of the proceeding schedule was unchanged.

On November 04, 2013, the Board held an oral public hearing in Whitehorse, Yukon. The Board was comprised of Bruce McLennan, Chair, and members Andre Fortin, Robert Boisvert and Naresh Prasad.

The Board directed parties to file final argument by December 02, 2013 and reply argument by December 16, 2013. The Board considers the proceeding closed on December 16, 2013.

In reaching the determinations contained within this decision, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 YECL SALES AND REVENUE

2.1 Overview

YECL submitted that on a weather-normalized basis, total primary non-industrial sales are forecast to increase by 2.3 percent in 2013,[4] and 2.9 percent in 2014 and 2015. YECL further submitted that if it were to include the sales to YECL's industrial customer, Whitehorse Copper Tailings (WHCT), YECL's total sales — industrial and non-industrial — are forecast to grow by 2.6, 3.1 and 1.9 percent in 2013, 2104 and 2015 respectively.

YECL added that its sales and revenue forecast was based on a detailed analysis of historical data by community and customer class. This data was comprised of information gathered by YECL staff who work in the communities as well as consultation with the City of Whitehorse, Yukon government officials and local developers.

In Schedule 2.1 of the Application, YECL provided a summary of actual and forecast average number of customers, and sales and revenue by customer class for the period from 2008 to 2015. Information that was used to determine the residential sales forecasts by community, was provided by YECL in Attachments 1 to 21 of Schedule 2.

2.2 Original Residential and Commercial Sales forecast

The following table summarizes YECL's energy sales forecast by customer class for the 2013, 2014 and 2015 test years (test period). The table also includes corresponding actuals for 2011 to 2012, and 2012 normalized actuals.

Table 1. **YECL Energy Sales 2011-2015**

	Actuals		Normalized Actuals	Forecast Test Period		
Customer class	**2011**	**2012**	**2012**	**2013**	**2014**	**2015**
Residential	141,696	150,350	147,845	151,793	154,381	157,023
Commercial	150,591	159,562	158,271	161,564	165,095	168,549
Street Lights	3,598	3,771	3,771	3,725	3,789	3,854
Private Lights	581	560	560	554	544	534
Sub-total	296,466	314,244	310,448	317,636	323,809	329,959
Industrial	-	-		1,025	4,620	4,620
Total	296,466	314,244	310,448	318,661	328,429	334,579

Source: Application, Table 1, page 2-2.

[4] YECL submitted that the 2.3 percent growth in sales in 2013 was consistent with the recently Board -approved YEC 2013 forecast growth in wholesale sales to YECL of 2.26 percent. YECL Application, page 2-1.

In 2012, YECL submitted that it provided electricity services to approximately 16,700 non-lighting customers in its service area and supplied a total of 314.2 GW.h to residential, commercial and lighting customers. This, YECL pointed out:

> …represents an increase in total primary sales of 6.0%, following a 5.4% increase in 2011. Strong economic and population growth in 2010 and 2011 led to the highest housing starts in 2011 since 2006, which, in turn, contributed to a high growth in Yukon Electrical's customer gains in both residential and commercial sectors. This, coupled with colder than "Normal" weather and a move to use electricity for space heating in more recent housing developments, resulted in strong electricity sales in 2011 and 2012.[5]

However, for the test period, YECL submitted that the latest economic projection from the Yukon government suggests a sharp slowdown in the pace of economic activity for 2012 and 2013. The Yukon government expects slower population growth in 2013, dropping from 2.1 percent in 2012 to 1.3 percent. YECL pointed out that the Canada Mortgage and Housing Corporation forecast a 25-percent decrease in Whitehorse housing starts in 2012 as compared to 2011. YECL submitted that this economic and population growth slowdown is expected to impact YECL's customer growth and sales over the next few years.[6]

2.2.1 Residential sales forecast

Respecting its residential sales forecast, YECL submitted that the forecast has two key inputs, net customer additions and the average use per customer (UPC). The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast. YECL explained that the weather-normalized UPC is determined using a two-step approach, where:

> …in the first step, the historical average monthly UPC is regressed on reported monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in first step is multiplied by the difference between the actual HDD and the "Normal" HDD. "Normal" HDD is defined as a twenty-year rolling average of HDD.[7]

With regard to determining the Whitehorse forecast UPC, YECL explained that it "used the 2012 weather-normalized UPC, which [already] reflects the consumption increases due to space heating, as a base and [then raised] it by the most recent three-year average growth in weather-normalized UPC."[8] Notwithstanding, YECL added, the UPC increase related to electric space heating, was not expected to have any impact on sales beyond 2013, as the consumption increase is expected to be offset by a reduction in consumption due to the demand side management program.

[5] YECL Application, page 2-3, lines 4-10.
[6] YECL Application, page 2-3, lines 12-24.
[7] YECL Application, page 2-5, lines 18-22.
[8] YECL Application, page 2-5, lines 11-14.

2.2.2 Commercial sales forecast

With the exception of Whitehorse and Watson Lake, YECL submitted that the commercial UPC forecast for all communities is the most recent three-year average actual UPC for each community.

> The base year UPC for Watson Lake is obtained based on the most recent three-year actual UPC. For Whitehorse, the 2012 normalized UPC is used as a base year UPC. This is because of conversion of several secondary commercial customers to primary in recent years makes it inappropriate to use a three-year average.[9]

With respect to the determination of the Watson Lake and Whitehorse community sales forecasts, YECL explained that the forecasts take into account twelve large commercial customer additions,[10] that are anticipated during the test period. Therefore,

> To forecast Whitehorse and Watson Lake commercial energy sales over the test period, Yukon Electrical has first determined the base energy sales for each community, which is forecast by multiplying the forecast customer counts (excluding the new large customer additions), by the corresponding community base year UPC forecast… The commercial energy sales for Whitehorse and Watson Lake are then calculated by adding the base energy sales in each year to the specific energy sales of the new large commercial additions.[11]

For communities other than Watson Lake and Whitehorse, YECL indicated that the community energy sales forecast is calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.3 Updated Residential and Commercial sales forecast

On October 31, 2013, YECL updated its application (updated forecast) "to ensure that the Board has the best and most recent information available to it on the record."[12] In its updated forecast, YECL submitted that it had updated its residential and commercial forecasts to reflect

> …what has happened in 2013 year-to-date and what can be reasonably be expected to occur for 2014 and 2015. The impact of the update on residential sales is a reduction to the forecast of 3.8 GWh for 2013, 3.8 GWh for 2014 and 3.9 GWh for 2015. For commercial sales, the impact of the update is a reduction to the forecast of 4.0 GWh for 2013, 4.1 GWh for 2014 and 4.2 GWh for 2015.[13]

YECL pointed out that actual residential energy sales for the first nine months of 2013 were 3.5 GW.h lower on a normalized basis than what was originally forecast, while customer additions had increased by 33 year-to-date over what was originally forecast. Accordingly, YECL submitted that it was lowering its 2013 residential sales forecast to 148.0 GW.h from 151.8 GW.h. YECL also submitted that it was basing the update of its

[9] YECL Application, page 2-6, lines 11-15.
[10] Commercial customers whose demand is greater than 100 kW; eleven in Whitehorse and one in Watson Lake.
[11] YECL Application, page 2-6, lines 7-17.
[12] Exhibit B-11, YECL updates to 2013-15 GRA, October 31, 2013, page 1 of 9.
[13] Exhibit B-11, YECL updates to 2013-15 GRA, October 31, 2013, page 2 of 9.

residential forecast on an "aggregate three year (2010 to 2012) average normalized UPC"[14] as was done in its 2008-09 GRA. YECL further submitted that, as was done in the Application, it would continue "to hold the updated 2013 UPC forecast for 2014 and 2015 in consideration of the offsetting impacts of the DSM program."[15]

As a result of commercial sales being lower in the first nine months of 2013 than was originally forecast, YECL submitted that it was lowering its 2013 forecast commercial sales from the original forecast of 162.5 GW.h to 157.6 GW.h. YECL attributed the over-forecast to its use of the 2012 normalized UPC for Whitehorse as the baseline. As was done in its application, YECL indicated that it was increasing its UPC in 2014 and 2015 to reflect the addition of specific customers greater than 200 kW.

The following table compares YECL's original residential and customer sales forecasts with the updated forecasts.

Table 2. **Comparison of Original and Updated energy sales forecast (kWh)**

	Original Forecast			**Updated Forecast**		
Customer class	2013	2014	2015	2013	2014	2015
Residential	151,793	154,381	157,023	148,010	150,531	153,101
Commercial	161,564	165,095	168,549	157,606	161,011	164,329

Source: Exhibit B-11, YECL updates to 2013-15 GRA, October 31, 2013, Attachment 1

YECL submitted that it did not know the nature of what was underpinning the lower-than-forecast customer energy sales in the Application.

YECL acknowledged that although a large number of its customers were using electric space heating in the newer condominium developments, the average UPC per customer is lower than UPC on average for all of its other customers. When asked to explain its use of a single-year (2012) UPC in the original application, YECL stated that the best information available at the time suggested that using a three-year average UPC might not be fair and reasonable, albeit subsequent actual 2013 customer energy sales indicated that the use of a one-year UPC was incorrect.[16] YECL pointed out that based on the latest available information it had reverted back to the forecasting methodology used in its last GRA, which "is a three-year average normalized use per customer."[17]

2.2.4 Views of the interveners

YEC submitted that YECL's updated forecast included a major reduction in YECL's forecast residential and commercial sales on the hydro grid relative to what was provided in the Application and reviewed during the information request (IR) process. The major reduction was related to the 2013 forecast non-industrial grid sales:

[14] Exhibit B-11, YECL updates to 2013-15 GRA, October 31, 2013, page 3 of 9.
[15] Exhibit B-11, YECL updates to 2013-15 GRA, October 31, 2013, page 3 of 9.
[16] November 7, 2013 transcript, page 635, lines 5-16.
[17] November 7, 2013 transcript, page 639, line 5.

> …the change for this one year (-7.7 GW.h) accounts for 95% of the total change for 2015 (8.1 GW.h) – indicating that forecast annual growth rates from the Application have been retained for 2014 and 2015.[18]

YEC was concerned that the reduced non-industrial grid sales forecast for 2013, if adopted, would set a new precedent in that it would allow for an adjusted GRA load forecast based on actual results at the time of a hearing. YEC submitted that YECL's proposed downward adjustment was too severe for 2013 non-industrial grid sales.

> In its Update to the Application YECL noted that "[t]he 2013 forecast is now based on the aggregate three year (2010-2012) average normalized UPC and, in addition, reflects the actual increase in customer additions of 33." Based on the evidence, the magnitude of the YECL forecast update reductions are not explained by reversion to three average normalized UPC. [Footnotes omitted][19]

YEC noted that YECL in response to YEC-YECL-3(c) had previously provided the impact of using a three-year average UPC for Whitehorse residential sales forecasts compared to the 2012 weather normalized UPC used in the Application.

> The impact was in the range of 1.2-1.3 GW.h for 2013-2015 test years. The UPC used for Whitehorse residential sales forecast in original Application [w]as 11,211 kW.h/customer based on 2012 weather normalized UPC plus 0.7% increase compared to 11,083 kW.h/customer based on a 3-year average weather normalized UPC or decrease of 129 kW.h/customer. This multiplied by forecast number of residential customer would result about 1.8-1.9 GW.h reduction in residential sales forecast in contrast to 3.8- 3.9 GW.h reductions in total YECL residential sales forecast in the Update for the test years.[20]

YEC asserted that the updated forecast as filed could not be fully tested at this late date and that there is limited ability as well for the Board to assess any specific alternative adjustment that could be made to the original application. YEC therefore recommended that the Board retain YECL's non-industrial forecasts per the original application to reflect normal regulatory review practice. However, if the updated forecast is to be allowed to reflect actual results, YEC submitted that the 2013 residential and commercial sales reductions to the original application should be limited to no more than 50 percent of what has been proposed by YECL. Furthermore, this adjustment should be consistently carried through to adjusted 2014 and 2015 forecasts — allowing for two-percent growth in 2014 and 2015.

> …the end result will increase YECL Update grid generation requirements by at least 4.1 GW.h in 2013 and slightly more in 2014 and 2015.[21]

Responding to YEC's submission above, YECL asserted that YEC-referenced numbers have no evidentiary support and cannot be relied upon by the Board for purposes of rendering its decision on these issues. Furthermore, there was no rationale or justification in YEC's argument in support of its proposed 50- percent reduction related

[18] YEC Final Argument, page 18.
[19] YEC Final Argument, page 19.
[20] YEC Final Argument, page 19, footnote 55.
[21] YEC Final Argument, page 21.

to the updated forecast. YECL submitted that YEC's calculations, in part, are based on its approved 2012-13 GRA forecasts, which are at least 18 months old and "clearly not the latest and best information available for forecasting Yukon Electrical's sales at this point in time."[22] Respecting its updated forecast, YECL reiterated its submission that the decrease in customer sales (residential and commercial) relative to the original forecast on a normalized basis for the first nine months of 2013, was attributable to a decrease in UPC.

> Incorporating the January-September reduction in UPC as well as well as the increases in the year-to-date customer additions for residential and commercial, Yukon Electrical has provided an updated energy sales forecast for 2013 of 309.9 GW.h. This update is 7.7 GW.h lower than original forecast of 317.6 GW.h. This decrease was then incorporated into the 2014 and 2015 updated sales forecasts which were reduced 7.9 GW.h and 8.1 GW.h, respectively. The year over year percent increase in the sales forecast for 2014 and 2015 remains at 1.9% per year which is consistent with the original forecast.[23]

YECL submitted that its updated forecast represents the best information available on the record for each of the test years. Furthermore, since YECL has applied for a three-year test period, YECL stressed the importance of having the best information available on the record. Referring to Board Order 2009-02, wherein the Board concluded that it may consider the best information on the record when it approved the use of YECL's actual 2008 long-term debt rate as opposed to the original forecast, YECL submitted that the Board should apply the principle consistently.

UCG expressed its concerns with the updated forecast submitting that "YECL's current forecast product, calculated retrospectively, but utilized prospectively,"[24] could have an impact on energy prices. Furthermore, the weather normalization process may impact the determination of test year sales used in a rate proceeding because electricity service and revenues are weather-dependent. In view of that, UCG submitted that the Board must satisfy itself that YECL has used an appropriate industry standard methodology to assess its energy requirements.

UCG submitted that YECL's sales forecasts incorporates a methodology that is too simplistic and does not incorporate the realities associated with Yukon-specific load data, does not incorporate adequately determined impacts of current and proposed DSM activities, and fails to gather and use input from stakeholders — e.g. other utilities with experience in addressing climate normal and current climate trends. UCG asserted that "that it is an anomaly to have any utility use only 3 years of actual load data in order to adequately forecast weather-normalized loads going forward." UCG pointed out that YEC load forecast reflects adjustments for weather conditions based on a 10-year average heating degree days.[25]

In response, YECL submitted that it has incorporated weather-normalization sales forecasts in its applications since preparing for its 2008-09 GRA. Moreover, YECL

[22] YECL Reply Argument, paragraph 13.
[23] YECL Reply Argument, paragraph 17.
[24] UCG Final Argument, paragraph 98.
[25] UCG Reply Argument, paragraph 27.

submitted that it included a Study on Canadian Energy Forecasting Methodologies, which contained discussions on weather normalization, in Section 11, Attachment 1 of the Application. YECL recommended that the Board dismiss the UCG recommendations.

2.2.5 Views of the Board

The Board notes YECL's submission in the Application that it forecasts the total primary non-industrial sales in 2013 to increase 2.3 percent (on a weather-normalized basis), and the 2.3-percent growth in sales in 2013 was consistent with the recently applied-for and Board-approved YEC 2013 forecast growth in wholesale sales to YECL of 2.26 percent.[26] The Board further notes YECL's explanation regarding the use of a one-year 2012 UPC for Whitehorse was to reflect the consumption increases due to space heating in the newer development areas in Whitehorse and area.

Subsequently, YECL updated is forecast, reverting back to the use of a three-year average UPC, which method had been used and approved in the past. The Board has concerns regarding YECL's updated forecast. During the hearing, YECL was questioned as to how the update accounts for the move to electricity for space heating. YECL testified that:

> … we were finding that we were - - actuals were coming in lower than what we had forecast on a normalized basis by about 2.3 per cent.
> We don't quite have a good understanding exactly why that has happened, but the fact is that the sales are coming in lower than what we had originally forecast on a normalized basis.
> …
> So exact cause as to whether it's related to space heating, it could be because of the warmer weather, but, however, when we take out the weather component, we're still experiencing lower than sales – lower than forecast sales.[27]

From the above, the Board is not convinced that the change in methodology on which the updated forecast is based is warranted. The Board accepts YECL's forecast update for 2013 but is not convinced that 2014 and 2015 should be changed from the original forecast. The Board directs YECL to reflect this finding in its revenue requirement and all related schedules in its compliance filing. In addition, the Board directs YECL in its compliance filing to adjust its sales forecast based on the findings from the DSM section of this decision.

2.3 Industrial sales deferral account

YECL indicated that a new industrial customer, Whitehorse Copper Tailings (WHCT) was forecast to start operations in the fall of 2013, albeit the timing of the customer's startup was uncertain. Nevertheless, YECL submitted a WHCT load forecast of 1,025 megawatt-hours (MWh) for 2013 and 4,620 MWh in each of the remaining years of the test period.

[26] YECL Application, page 2-1.
[27] November 7, 2013 transcript, page 631, line 25 to page 632, lines 1-6 and page 632, lines 12-16.

In consideration of the uncertainty surrounding the project and the magnitude of the load, YECL requested a deferral account relating to the WHCT sales uncertainty. YECL submitted that the proposed deferral account is intended:

> … to capture the difference between WHCT net revenue on existing Rate 39 less forecast purchase power price applied to forecast sales, and WHCT net revenue on existing Rate 39 less forecast purchased power price applied to actual sales.[28]

Subsequently, in its updated forecast, YECL submitted that WHCT project construction will not begin in 2013:

> WHCT is now hoping to build in late winter or early spring of 2014, which would require Yukon Electrical to provide construction power, with full electricity supply required for production required two to three months later.[29]

When asked to provide an example wherein the Board allowed the creation of a deferral account that was related to a utility's forecast sales, YECL submitted that the "YUB ordered the creation of a deferral account related to the sales of Yukon Energy to the Faro mine site under Rate Schedule 34."[30] YECL further clarified that Rate Schedule 34 was associated with the provision of site maintenance energy when Rate Schedule 39 was not in effect and no mining or milling activities were taking place.

2.3.1 Views of interveners

With respect to Rate Schedule 34, UCG submitted that it understood that "YEC collected revenues from the Federal Government for the ongoing shutdown and de-watering power requirements at the Faro mine site."[31] As such, UCG submitted that the Faro mine de-watering deferral account was a completely different account than the deferral account YECL was proposing. Furthermore, from UCG's standpoint, the proposed WHCT sales uncertainty deferral account transfers the risk of serving this industrial customer to non-industrial customers. UCG submitted that, given the delay in the startup of WHCT as an industrial customer, the impact of any forecast error during the test period would be minimal and there was no need for the deferral account.[32]

YEC submitted that the implementation of a deferral account as proposed by YECL to address sales uncertainty is unprecedented in Yukon and materially shifts risk from the utility to all ratepayers. Referring to Rate Schedule 34, YEC submitted that the context for this deferral account was very different from what YECL is proposing in that it addressed the:

> …post shut-down Faro mine situation where site maintenance energy was urgently required with no clear basis for any forecast of ongoing load. In this

[28] YECL Application, pages 2-8, lines 5-8
[29] Exhibit B-11, YECL updates to 2013-15 GRA, October 31, 2013, page 8 of 9.
[30] Information Responses, UCG-YECL 10(a).
[31] UCG Final Argument, paragraph 104.
[32] UCG Final Argument, paragraphs 111 to 112.

context, all of the net revenue benefits from the actual sales went 100% to the account of ratepayers.[33]

YEC noted that YECL's updated filing acknowledged that the WHCT load would not materialize in 2013. However, while the filing updated other areas of the residential and commercial sales forecast, the industrial load forecast was not updated. Referring to YEC-YECL-6(d),[34] wherein YECL provided an example of the proposed deferral account calculation that assumed WHCT not operating in the test period, YEC pointed out that not updating the industrial load forecast allowed YECL to "book $52,269 net income for 2013 with deferred collection from other customers without any risk…"[35] For these reasons, YEC recommended that YECL update its test period WHCT load forecast in the compliance filing. Further, YEC submitted that, under the current circumstances and based on the past precedent of the Faro site maintenance deferral account, if WHCT load were not included in the YECL revenue requirement, it was possible to consider a deferral account to deal with the WHCT load uncertainty.

YEC concluded by stating that the above approach protects both YECL and all other ratepayers, and facilitates the WHCT load connection if and when this becomes possible.

LE acknowledged and recommended that the Board approve YECL's proposed WHCT forecast sales deferral account.

YECL acknowledged YEC's and LE's argument that its proposed WHCT forecast sales deferral account be accepted, while UCG's submission conversely suggested that there was no need for the deferral account. While agreeing with YEC that YEC's approach protects YECL and ratepayers, YECL noted that the latest available information suggests that WHCT will begin to take service in the spring of 2014. Noting UCG's submission that there was no need for the deferral account, YECL submitted that its proposal meets the deferral account criteria and will protect both YECL and ratepayers from significant variances that may arise regarding WHCT sales uncertainty.[36]

2.3.2 Views of the Board

Respecting rate schedule 34, the Board notes the UCG submission and agrees that the Faro mine de-watering deferral account is a completely different account than the deferral account, which YECL is proposing. The Board further notes that the standard criteria for the establishment of a deferral account include: (a) costs that are not under the control of the company and are not reasonably forecastable, or (b) where an error in forecasting could produce a loss or gain of a substantial magnitude. In its forecast update, YECL submitted that it expects to provide construction power in late winter or early spring of 2014 and full electricity supply for production two to three months later. In view of YECL's forecast update, the Board considers that WHCT startup is reasonably forecastable for 2014, and any forecasting error respecting the startup is minimal. Accordingly, the Board denies YECL's proposal for a deferral account related to WHCT

[33] YEC Final Argument, page 13.
[34] Exhibit B-7, YECL information responses, August 29, 2013.
[35] YEC Final Argument, page 14.
[36] YECL Reply Argument, paragraphs 21 to 23.

sales uncertainty. The Board therefore, directs YECL in its compliance filing to reflect the Board's findings and to update the WHCT sales forecast.

3 PURCHASE POWER

YECL submitted that its purchase power costs were to increase over the test period due to "increased purchases resulting from sales load growth … net of increased hydro generation at Fish Lake as a result of Unit #1 coming back into service in December 2013."[37] The following table shows the actual and forecast purchase power over the period from 2008 to 2015.

Table 3. **Actual and forecast purchase power – 2008 to 2015 ($000)**

	Actuals					Test Period		
	2008	2009	2010	2011	2012	2013	2014	2015
Primary purchase power	18,046	18,278	18,902	21,941	25,746	25,999	26,472	27,013
Secondary purchase power	1,190	907	553	40	142	-	-	-
Shortfall Rider J	4,990	4,026	4,353	2,479	1,437	-	-	-
Less: capitalized[38]	(69)	-	(346)	(367)	(402)	(369)	-	-
Total Purchase Power	24,157	23,211	23,462	24,093	26,923	25,630	26,472	27,013

Source: Application, page 3-1

YECL submitted that since the March 2010 catastrophic failure of Fish Lake unit #1, YECL has purchased approximately 93 percent of its required power supply from YEC. The remainder of YECL's power supply requirements has been provided by diesel generation and by hydro generation from Fish Lake unit #2. For the test period, YECL indicated that the percentage of its power supply requirements purchased from YEC is forecast to decrease slightly in 2013, and to decrease to approximately 91 percent in 2014 and 2015, as Fish Lake unit #1 comes back on-line near the end of 2013.[39] YECL further clarified that the Fish Lake generation forecast in the test period was based on the Fish Lake base hydro generation of 8.73 GW.h, which was approved in Board Order 2009-02, adjusted for downtime of unit #1 for 2013.

YECL was asked to explain why the Fish Lake generation forecast should not be greater than what was approved in Board Order 2009-02, considering that the Fish Lake infrastructure had been updated with current engineered standards and equipped with more efficient apparatuses. YECL submitted that historical averages related to Fish Lake from 1960 to 2012 indicate that 8.73 GW.h is higher than what should be forecast for the test period:

[37] YECL Application, page 3-1, lines 5-8.
[38] YECL was directed in Board Order 2009-02 to capitalize the incremental purchased power costs incurred due to Fish Lake rebuilds in 2008/2009. Consistent with this Order, YECL has capitalized the incremental purchase power costs incurred for the period in which Fish Lake unit #1 was out of service after the March 2010 catastrophic failure.
[39] YECL Application, page 3-1, lines 10-17.

1. The 50-year historical average is 8.48GWh;

2. Only two time periods (the 1960s and 1970s) exceed the 8.73GWh approved by the Board in Order 2009-02; and

3. There is a high variability in output with the lowest average 10-year output of 7.42GWh occurring in the 2000 – 2009 time period.[40]

Furthermore, YECL did not have any experience with the new equipment and it was not clear what the efficiency gain will be considering that any efficiency gains are subject to operational flows. YECL therefore submitted that the best forecast available for purposes of this application was to remain at the Board-approved 8.73 GW.h output.[41]

When asked what Yukon ratepayers could expect in terms of benefits from the Fish Lake unit #1 turbine and building replacement project, YECL submitted that it expected an approximate 13-percent increase in output, $22,000 lower operating costs, and that the incremental cost of the unit would be paid back in a reasonable time frame[42]. YECL added that, in future, the expected annual Fish Lake unit #1 generation output was 5.6 GW.h.[43]

3.1 Views of interveners

YEC agreed with YECL's proposal to remain with the Board-approved output of 8.73 GW.h per year for 2014 and 2015.[44] Conversely, considering the expected efficiency gains, a:

> … 13% increase from 5.6 GWh per year adds 0.73 GWh per year, and adding 0.73 GWh per year to the 50 year average of 8.48 GWh per year is 9.21 GWh per year.[45]

LE submitted that a new long-term average generation level of 9.21 GW.h should be set for the Fish Lake hydro system.

YECL reiterated its submission that that it did not have any actual experience with the newly installed equipment at Fish Lake and that the best forecast available for purposes of this application was to remain at the Board-approved output of 8.73 GW.h "rather than decreasing the expected output at the Fish Lake facility to better match the historical average and then offsetting it with potential efficiency gains."[46]

3.2 Views of the Board

Considering the long-term averages submitted by YECL and the lack of clarity respecting the efficiency gains related to the installation of new equipment, the Board for purposes of this application accepts the 8.73 GW.h annual generation output for the test period. Accordingly, the Board rejects LE's submission that a new long-term

[40] Information Responses, YUB-YECL-37 (d).
[41] Information Responses, YUB-YECL-37 (d).
[42] Information Responses, YEC-YECL-17 (c).
[43] Information Responses,YEC-YECL-17 (d).
[44] YEC Final Argument, page 22.
[45] LE Final Argument, page 7.
[46] YECL Reply Argument, paragraph 24.

average annual generation level of 9.21 GW.h should be set for the Fish Lake hydro system.

3.3 Capitalization of incremental purchase power when Fish Lake down

YECL indicated that, consistent with Board Order 2009-02, it was seeking to capitalize incremental purchase power costs that it had incurred for the period in which Fish Lake unit #1 was out of service as a result of the March 2010 catastrophic failure.[47] Responding to UCG-YECL-11 (a), YECL confirmed that it had incurred incremental purchase power costs of $346,000, $367,000, $402,000, and $369,000 respectively in 2010, 2011, 2012 and 2013.

In the hearing, YECL confirmed that Board Order 2009-01 preceded the catastrophic failure of Fish Lake unit #1. When asked what part of the order applied to situations of catastrophic failure as well as of planned capital upgrades, YECL responded:

> The underlying substance-over-form of the situation was that Fish Lake was down as a result of a planned overhaul in 2008, and as a result of Decision 2009-02, the additional purchase power that was required due to that planned overhaul in 2008 was ordered by this Board to be capitalized as part of that overhaul.
>
> The substance of the situation with regards to the catastrophic failure in 2010 is that the Fish Lake is down for being rebuilt; substance-over-form, the additional purchase power associated with Fish Lake being down has been capitalized.
>
> So it's, from our perspective, the exact same situation in both of those instances.[48]

Furthermore, when asked about other instances where incremental purchase power costs resulting from unavailable generation due to a planned or unplanned outage had been capitalized, YECL affirmed that there were generation costs associated with the Carmacks-Stewart transmission line project (CSTP), which were incurred by YECL that were capitalized as part of the project.[49]

Explaining how the incremental power costs incurred when Fish Lake unit #1 went out of service would have enduring benefits for ratepayers, YECL submitted that "the capitalization of purchase power is just another input that is part of that overall cost to get Fish Lake up and running …"[50] Furthermore, these costs were incurred as part of the total capital project of rebuilding Fish Lake, "which will have enduring benefits for ratepayers for many years to come" and Yukon Electrical submits that the capitalization of these costs should be approved as filed.[51]

[47] YECL Application, page 3-1, footnote 1.
[48] November 6, 2013 transcript, page 404, lines 6-19.
[49] November 5, 2013 transcript, page 206, lines 11-20.
[50] November 5, 2013 transcript, page 207, lines 10-12.
[51] YECL Final Argument, paragraph 23.

3.3.1 Views of interveners

LE submitted that the purchase power costs that resulted from the Fish Lake catastrophic failure were very different from the purchase power costs approved in Board Order 2009-02. LE disagreed with YECL's capitalizing all of the purchase power costs from March 2010 to December 2013, and suggested that most, if not all, of the purchase power costs that YECL has applied for in this application should be charged to the reserve for injuries and damages (RID). Furthermore, including:

> …the purchase power cost in the capital cost of Fish Lake Unit #1 replacement artificially raises the capital cost of the project and the levelized cost of energy from the project. At most the downtime that would have been required for a planned replacement of the unit should be included in capital costs.[52]

LE further submitted that only the purchase power costs that YECL incurred in 2013 should be approved for inclusion in the capital cost of Fish Lake unit #1 replacement. Accordingly, LE recommended that the Board direct YECL to calculate the purchase power cost for the three-year period of March 2010 — the date of the catastrophic failure — to December 31, 2012 and that this amount should be recovered from the reserve for RID or absorbed by YECL. Alternatively, LE recommended that the Board direct the entire purchase power cost from March 2010 to the December 2013 in-service date be recovered from the RID.[53]

YECL acknowledged that charging incremental purchase power to the RID was an option to consider. However, YECL submitted that this option was not chosen "due to Board Order 2009-02 and its direction to capitalize incremental purchased power."[54] Furthermore, whether the incremental power is charged to RID or YECL's preferred option has no effect in the long run, albeit the proposed option reduces the rate impact in the test years.[55]

UCG noted that Board Order 2009-02 allowed the amortization of capital costs associated with the incremental purchase power costs because they were related to the rebuild which would have enduring benefits. Referring to YECL's submission that there were generation costs capitalized as part of the CSTP, UCG stated that there was no evidence on the record that validated this claim. Furthermore, the incremental purchased power costs incurred when Fish Lake was out of service served an immediate need just as any source of power might have in an emergency situation and does not provide enduring benefits to ratepayers. Accordingly, UCG submitted that these costs should not be capitalized.[56]

YECL replied that Board Order 2013-01 directed YEC to include its own, as well as third party, generation costs in the determination of total costs associated with its capital

[52] LE Final Argument, page 2.
[53] LE Final Argument, page 2.
[54] YECL Reply Argument, paragraph 27.
[55] YECL Reply Argument, paragraph 27.
[56] UCG Final Argument, paragraphs 124 to 126.

projects. YECL submitted that the same should hold true for YECL. Furthermore, if YECL were directed to:

> …absorb any portion of the costs of the incremental purchase power that it has proposed to be capitalized as part of this Application would not only be unfair, but it imports a finding that Yukon Electrical has been imprudent in its rebuilding of Fish Lake Unit #1 and there is quite simply no evidence to support such a conclusion.[57]

Accordingly, YECL submitted that its proposed capitalization of these costs should be approved as filed.

3.3.2 Views of the Board

The Board agrees with LE that the purchase power costs that resulted from the Fish Lake catastrophic failure are different from the purchase power costs approved in Board Order 2009-02. The Board's determination in Board Order 2009-2 was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with the Fish Lake hydro rebuilds."[58] Furthermore, respecting Board Order 2013-01, the generation costs that YEC was directed to include related to a planned capital project.

Respecting the purpose of the reserve, the Board notes YECL's submission that the reserve is established for the payment of uninsured and uninsurable losses resulting from but not limited to design error, failure to supply — blackout or brownout — professional liability and pollution liability.[59]

Considering the above, the Board rejects YECL's proposal to capitalize incremental purchase power costs that it had incurred for the period in which Fish Lake #1 was out of service as a result of the March 2010 catastrophic failure. The Board therefore directs YECL to recover all costs related to the catastrophic failure of Fish Lake unit #1 for the period from March 2010 to the end of 2013, when Fish Lake comes back on line, from its reserve for injuries and damages account. The Board further directs that YECL reflect this determination in its compliance filing.

4 FUEL COSTS

Fuel costs included in the YECL application are as follows:

Table 4. **Actual and forecast fuel costs – 2008 to 2015 ($000)**

	Actual				Test Period			
	2008	2009	2010	2011	2012	2013	2014	2015
Fuel Costs	6,603	3,758	5,146	5,539	5,637	6,611	6,701	6,704

Source: Application, page 4-1

[57] YECL Reply Argument, paragraph 29.
[58] Board Order 2009-2, Appendix A, Reasons for Decision, page 9.
[59] YECL Application, Section 8, Attachment 1.

YECL explained that it purchases fuel on an ongoing basis for each of its five isolated diesel plants via a diesel fuel tendering process,[60] by means of which a vendor is selected to be the provider of diesel fuel to YECL. YECL further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

YECL submitted that the fuel cost increase of $974,000 from 2012 to 2013 was mainly due to the inclusion of Rider F in test period base rates. Prior to 2013, YECL recovered the difference between the forecast 2009 fuel rates and the current fuel rates using Rider F.

YECL explained that the variance between actual and forecast fuel prices are refunded to or recovered from customers by means of Rider F, a fuel price flow-through rider.

> The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or 'heat rate', kWh / Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.[61]

YECL is proposing to continue the deferral for fuel prices for the test period. YECL explained that, beginning in 2013, however, it would be sourcing a supply of liquefied natural gas (LNG) for the Watson Lake bi-fuel project from FortisBC. Accordingly, YECL, requested a change in the methodology to account for the conversion of the diesel units in Watson Lake to bi-fuel (diesel and LNG).

> [B]eginning in the fall of 2013, generation with be based on a variable mix of diesel and LNG. [YECL does not yet have any historical data in respect of bi-fuel operations at Watson Lake.] This means that the forecast plant efficiency cannot be determined at this time. In order to address this issue, Yukon Electrical is requesting to use the actual equivalent diesel litres used as opposed to derived litres that are based on a forecast plant efficiency to arrive at the fuel deferral amount for Watson Lake. For all other locations, the calculation of the fuel price deferral would remain [as] previously approved.[62]

With respect to the LNG usage in Watson Lake, YECL proposed that fuel costs be converted to equivalent diesel litres using industry standard conversion factors for the calculation of the fuel price flow-through deferral balance.[63] YECL submitted that the industry-accepted formula for conversion is:[64]

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[60] Current diesel fuel arrangements are to be retendered in 2014; Application, page 4-1, line 14.
[61] YECL Application, page 4-2, lines 22-23 to page 4-3, lines 1-3.
[62] YECL Application, page 4-3, lines 7-13.
[63] YECL Application, page 4-3, lines 14 to 16.
[64] Information Responses, UCG-YECL-19(d).

$$[Die \qquad\qquad t]$$

$$[\mathrm{L} \qquad \mathrm{NG}] \quad \frac{[MJ \;\; L]}{\mathrm{l}\,[\mathrm{MJ}\;\; \mathrm{L}]}$$

Where: Energy Content of LNG = 22.6[65]

Energy Content of Diesel = 38.7[66]

4.1 Views of interveners

UCG submitted that the Board cannot approve the proposed fuel price flow-through deferral account and the proposed methodology for calculating the deferral for fuel used in Watson Lake "without changing the Fuel Adjustment Rider & Deferred Fuel Price Variance policy and without having Section 8 of the Rate Policy Directive Order-in-Council 1995/90 changed to account for LNG."[67] LE, on the other hand, submitted its recommendation that the Board approve YECL's proposal to use the equivalent diesel litres if the Board approves the Watson Lake bi-fuel project.

YEC agreed in principle that the existing fuel price flow-through deferral account should be adjusted to accommodate the use of LNG. However, YEC noted that with respect to YECL's proposed changes to the deferral account, the specific change requested was to convert LNG fuel costs to equivalent diesel litres based on energy content. Respecting the conversion, YEC noted that a litre of LNG will be assumed to have

> …58% the HHV energy content of a litre of diesel. No assessment is provided as to the choice in this regard between HHV and LHV for this conversion, no examples have been provided as to how this would be done in practice, and the forecasts in the Application appear to make no provision for any of the expected cost savings at Watson Lake as a result of the use of LNG. [Footnotes omitted][68]

YEC therefore recommended that the Board direct YECL to provide examples of how it will provide for LNG costs in its fuel price flow-through deferral account and in future Rider F determinations to ensure that all fuel price cost savings from LNG use at Watson Lake are passed on to ratepayers.[69]

YECL disagreed with UCG, explaining that, as submitted on page 1-5 of its application, the deferral accounts for which YECL is seeking approval meet the standard criteria for the establishment of a deferral account:

> …diesel and LNG fuel costs are not under the control of Yukon Electrical and are not reasonably forecastable; [and] an error in forecasting could produce a loss or a gain of a substantial magnitude.[70]

[65] YECL Application, page 4-4.
[66] YECL Application, page 4-4.
[67] UCG Final Argument, paragraph 131.
[68] YEC Final Argument, pages 10-11.
[69] YEC Final Argument, page 11.
[70] YECL Reply Argument, paragraph 33.

YECL explained that these criteria continue to be met regardless of whether YECL generates electricity in Watson Lake exclusively with diesel or with a combination of diesel and LNG. Moreover, with respect to Section 8 of the Rate Policy Directive Order-in-Council 1995/90, YECL submitted that the order:

> …provides for fuel price adjustments and sets out that the Board must permit Yukon Electrical and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to reflect fluctuations in the prices for diesel fuel, without the requirement for specific application to and approval by the Board.[71]

YECL submitted that, since it has not made any specific request to the Yukon government to change this directive, YECL recognizes that it must apply and receive the approval from the Board for any deferral accounts related to Watson Lake once bi-fuel generation begins in 2014. Accordingly, YECL is requesting the Board's approval of its proposed fuel price flow-through deferral account as part of this application.[72] Further, once the Board has ruled on the YECL requested deferral, YECL and YEC can file an updated policy that reflects the Board's decision.

With respect to YEC's submission, YECL submitted that it had provided examples of the deferral calculation in YEC-YECL-9(b), attachments 1 and 2. Moreover, YECL, in future applications will request approval of Watson Lake fuel price flow-through deferral account amounts, which by their very nature will ensure that all fuel price cost savings from LNG used in Watson Lake are passed on to ratepayers.[73]

In summary YECL, submitted that continued use of the approved fuel price flow-through deferral with the proposed modifications to account for future Watson Lake bi-fuel operations was reasonable and appropriate. YECL further submitted that no amendments to Section 8 of Rate Policy Directive Order-in-Council 1995/90 are required to facilitate this approval and it has provided examples of the mechanics of the conversion calculation.[74]

4.2 Views of the Board

Considering that the Board, in Section 10.8.2 of this decision, rejects YECL's proposed Watson Lake bi-fuel project, the Board finds that it is not necessary, at this time, to approve YECL's proposed change to the Rider F methodology to account for the conversion of the diesel units in Watson Lake to bi-fuel.

5 OPERATIONS AND MAINTENANCE EXPENSE

For 2013, 2014, and 2015, YECL has requested approval of operations and maintenance (O&M) expenses totaling $11.7 million, $12.3 million, and $12.5 million respectively. The Board notes that the actual O&M for 2010, 2011 and 2012 totaled $9.6 million, $9.8 million, and $11.1 million respectively.

[71] YECL Reply Argument, paragraph 33.
[72] YECL Reply Argument, paragraph 33.
[73] YECL Reply Argument, paragraph 35.
[74] YECL Reply Argument, paragraph 37.

5.1 Labour

In the Application, YECL submitted a forecast complement of 73.39 full-time employees (FTE) by the end of 2015. This was an increase of 6.86 FTEs over its 2012 actual ending complement and an increase of 15.96 FTEs over its Board-approved complement set out in Board Order 2009-02[75]. More specifically, YECL provided the following table to demonstrate the positions that had been added since 2009 and that it planned to add over the test period:

Table 5. **Full-time employee complement**[76]

	Full-time
2009 Approved Complement	**57.43**
Meter Reader (2010)	1.00
Senior Corporate Communications Advisor (2011)	0.60
Financial Analyst (2011)	1.00
Administrative Assistant (2011)	1.00
Planning Supervisor (2012)	1.00
Meter Reader (2012)	1.00
Corporate Accountant (2012)	1.00
Manager, Financial Reporting and Accounting, North of 60 (2012)	0.50
Engineer in Training (2012)	(1.00)
Construction Lead (March 2012)	1.00
Engineering Tech 1 Civil (October 2012)	1.00
Engineering Assistant (October 2012)	1.00
2012 Actual Ending Complement	**66.53**
Power Line Technician (PLT) Apprentice (2013)	1.00
Customer Service Advisor (2013)	1.00
Demand Side Management (DSM) Administrator (2013)	1.00
Customer Service Representative (2014)	1.00
Engineer in Training (2014)	1.00
Environmental Technician (2014)	1.00
Construction Assistant (2015)	1.00
Power Line Technician (PLT) Apprentice (2015)	1.00
Meter Reader (July 2015)	(1.00)
Various Other	(0.14)
2015 Forecast Ending Complement	**73.39**

In its updates filing, submitted on October 31, 2013, YECL submitted that the DSM costs presented in Business Case #30 included the costs of two positions that it had accidently excluded from the employee FTE complement presented in the Application. More specifically, YECL submitted that it planned to add both a Customer Engagement Officer and a Back Office Coordinator in 2014. Therefore, including these two FTEs, YECL's forecast ending complement for 2015 should be 75.39.

[75] Board Order 2009-02, Appendix A, Reasons for Decision on an Application by Yukon Electrical Company Ltd. for Approval of Revenue Requirements for 2008 and 2009, issued February 19, 2009.
[76] YECL Application, page 1-8.

In argument, YECL stated that it had provided a description of each of the FTE additions, and forecast FTE additions, occurring in the 2010 to 2015 period, as well as answered numerous questions on its FTE additions through IRs and cross-examination. YECL submitted that the totality of the evidence on the record demonstrates the need for all of the FTE additions noted in the Application.

YECL also argued that the information provided in Undertakings #29 to 34 and DSM 9 support the need for the Senior Corporate Communications Advisor, Meter Reader, Engineering Tech 1 Civil, and Customer Service Advisor positions. YECL also reiterated the need for the Environmental Technician position due to the more demanding regulatory and monitoring requirements.

5.1.1 Views of interveners

In argument, LE stated that it was concerned with YECL's labour costs escalating beyond sales and customer growth. LE submitted that growth in the FTE complement from Board-approved 2009 levels to actual 2012 levels was 15.8 percent and from approved 2009 levels to forecast 2015 levels was 31.3 percent. The increases in labour costs over the same periods are 16.7 percent and 32.0 percent respectively. LE further submitted that the increases in the number of retail customers over the same periods are 9.3 percent and 13.0 percent respectively. LE argued that the number of staff and the corresponding O&M are increasing at twice the rate of customer growth and are not justified. LE argued that economies of scale should not be working in reverse. LE further argued that although YECL points to capital projects and the growth in rate base as partial justification for the increases in the labour complement, capital projects have their labour costs allocated to the capital projects, not to O&M, so capital projects cannot be the cost driver.

LE recommended that the Board reduce at least two of the FTE additions forecast in the test years. More specifically, LE stated that the Customer Service Representative position, 2014 addition, could be eliminated due to the economic downturn in Yukon, which was described by YECL on page 2-3 of the Application, and the lack of market uptake of new residential lots in the Whistle Bend subdivision. LE argued that these developments meant that new connections and projects will be decreasing.

LE submitted that YECL used increased monitoring of Fish Lake as justification for the addition of an Environmental Technician in 2012 but also used increased monitoring of Fish Lake as partial justification to propose the addition of another Environmental Technician in 2014. LE recommended that one of these two positions can and should be eliminated.

LE stated in its argument that it was concerned with the number of additions in the finance and accounting area as well. LE stated that head office administrative expenses, which include financial reporting and regulatory support, will increase by a factor of 20 from the previous test years to the current test years. LE did not provide specific recommendations to address the increase but stated that it hoped the Board would address this matter.

In reply argument, YECL submitted that it would not have added any positions over the 2010 to 2012 period unless they were absolutely required since these additions were not approved in the revenue requirement.

In response to LE's suggestion that the Customer Service Representative is not needed, YECL noted that Attachment 1 in IR response LE-YECL-2(b) shows the number of capital projects in 2012 was 433, which is an increase from the 313 capital projects in 2009. YECL reiterated that the Customer Service Representative will work directly with customers to ensure their projects are designed, built and reviewed in accordance with the Terms and Conditions. YECL further submitted that the position is needed to address customer feedback and concerns regarding not having a single point of contact for capital projects.

With respect to the Engineering Tech 1 Civil, YECL submitted that the position has the lead responsibility for the Fish Lake Hydro system in scheduling and managing each infrastructure project to completion. YECL reiterated that the Engineering Tech 1 Civil has the responsibility to ensure the Fish Lake Hydro system complies with the water use license.

With respect to the Environmental Technician, YECL submitted that this position will be required due to the increased regulatory standards and reporting for diesel emissions, Fish Lake Hydro system monitoring, and environmental permits, as well as the increased number of mandated ecological and biological studies. YECL further submitted that the Environmental Technician will be responsible for environmental reporting requirements throughout YECL's business, not just the Fish Lake Hydro system.

YECL submitted that LE's concern that the number of additions in the financial and accounting area is greater than necessary is unsubstantiated. YECL argued that its staffing remains modest for a company that has close to $200 million in assets, has the reporting requirements of a publicly traded company, and operates with little to no help from third party regulatory consultants, except for legal. YECL determined in 2011 that operating with one financial professional who handled both financial and regulatory matters was unsustainable. YECL argued that even after the staff additions that took place in 2012, YECL still only had a 0.5 FTE Manager, Supervisor, Financial Services, and a Corporate Accountant, as opposed to having a Chief Financial Officer, a Controller and other financial manager positions that are found in organizational charts of other utilities.

With regard to LE's suggestion that if the Board is not comfortable specifying which positions should be cut, the Board should order a vacancy rate of four FTEs (or higher), YECL argued that there is no evidentiary support for this recommendation. YECL submitted that it had already included a vacancy rate of 3.4 percent (approximately two FTEs) in its application.

In reply argument, LE repeated its concern that YECL's labour costs are escalating beyond sales and customer growth. LE reiterated its recommendation that at least two of the FTEs added during the test period be cut. LE further reiterated that the Customer

Service Representative and the Engineering Tech 1 Civil or the Environmental Technician should be eliminated.

5.1.2 Views of the Board

The rate at which YECL's labour costs are escalating is a concern for the Board because the 2009 Board- approved complement of 57.43 FTEs has increased to 66.53 FTEs in 2012 and a further request for an additional 6.86 FTEs is contained in the Application. This would result in an overall increase of 16 FTEs from the approved 2009 complement. This is without the two DSM-related positions. If these are factored in the FTE count, it would result in an overall addition of 18 FTEs.

The Board agrees with LE that as companies and operations get bigger they should become more efficient and benefit from economies of scale; however, based on evidence on the record, the opposite appears to be happening. As LE pointed out in argument, the number of staff and the corresponding O&M costs are increasing at twice the rate of customer growth, and the head office administration costs are expected to increase by a factor of 20. The Board is of the view that more discipline must be exercised by YECL in the growth of its employee complement; however, the Board does not know, and will not speculate on, which positions are more important or necessary to the Applicant. In the Board's view, the Applicant knows best how to allocate and optimize its human capital resources.

Accordingly, the Board orders YECL to reduce its FTE complement in the test years by 3.0 FTEs, one of which must be from accounting and finance, and to provide an explanation in the compliance filing on how it plans to meet this reduction. More specifically, the Board approves a 2015 forecast ending complement of 70.39 (not including the two DSM-related FTEs YECL inadvertently excluded from its Application). The compliance filing should also provide a schedule demonstrating how these reductions will affect labour costs.

5.2 Vacancy Rate

YECL proposed a vacancy rate of 3.4 percent (2.0 FTEs) to be applied to all labour expenses for 2013, 2014, and 2015. Additionally, in response to YUB-YECL-19, YECL provided the raw data and calculations used to come up with the 3.4-percent vacancy rate.

5.2.1 Views of the Interveners

No interveners commented on YECL's proposed vacancy rates.

5.2.2 Board Findings

The Board has reviewed the data and calculations provided by YECL and agrees that the 3.4 percent vacancy rate is determined using an approach consistent with the methodology approved in Board Order 2009-02. Accordingly, the Board approves the 3.4 percent vacancy rate for the test period.

5.3 Labour Inflation

In the Application, YECL submitted a labour inflation rate of 3.5 percent for 2013, 2014, and 2015 for both in-scope and out-of-scope labour. YECL stated that the 2013 and 2014 escalations were based on its collective agreement that expires on December 31, 2014 and the 2015 escalations are based on its forecast of the increase required.

In argument, YECL reiterated its labour inflation rate forecast for the test period and further submitted that its forecast labour inflation rates are supported by a number of recent decisions and collective agreements. More specifically, YECL referenced Decision 2013-358 by the Alberta Utilities Commission, which approved forecast labour inflation rates of 3.5 percent for each of 2013 and 2014, and collective agreements made by its northern affiliates Northland Utilities (NWT) Ltd. and Northland Utilities (Yellowknife) Ltd.

5.3.1 Views of the Interveners

No interveners commented on YECL's labour inflation forecasts.

5.3.2 Views of the Board

The Board recognizes that YECL's labour inflation forecasts have been reviewed in this proceeding and, in light of the awards in other jurisdictions, is confident that the labour inflation forecasts provided by YECL are reasonable for the test period. Accordingly, the Board approves YECL's labour inflation forecasts as requested.

5.3.3 Capitalization of Labour

YECL submitted in the application that a portion of labour costs are allocated to capital accounts depending on the nature of work being performed over the test period.

5.3.3.1 Views of the interveners

With regard to the capitalization of labour, UCG contended in argument that YECL had confirmed during the oral hearing that they did not have any evidence that their 33-percent to 34-percent level of labour proposed for capitalization in 2013 through 2015 is comparable to other utilities. UCG argued that transferring an arbitrarily set and non-benchmarked 33 percent of labour costs to YECL's balance sheet as an asset allows YECL and its shareholders to earn returns on what appears to be a fictitious number that appears too high to be reasonable.

UCG submitted that the Board should reject YECL's proposal to capitalize 33 percent to 34 percent of its labour costs because YECL has not adequately demonstrated that the additional overhead included in the test year forecasts is directly attributable to particular capital activity.

UCG also added that it was concerned that the 33-percent to 34-percent ratio is based on a snapshot calculation without consideration of historical trends. UCG submitted that 27 percent to 30 percent of labour should be assumed to be capitalized in the test years until a more formal industry standard can be determined.

UCG argued that the purpose of capitalizing administrative and general overhead as part of the total cost of a capital asset is to ensure that all costs associated with constructing a capital asset, including those related to administrative activities, labour, et cetera, are included. This allocation results in a better matching of the costs incurred with the timing of the benefits they generate. The amount of capitalized overhead will vary from year to year based on the mix of capital versus operating and maintenance activities undertaken and based on any changes to the methods used to allocate costs between activities.

UCG also recommended that YECL's overhead capitalization policy and implementation of that policy should be subject to an independent study to ensure that capitalized overhead is directly attributable to particular capital activities and that historical trends and industry practice are fully considered.

In reply argument, YECL submitted that despite UCG's statement that the percentage of labour capitalized in the test years is "arbitrarily set" and a "fictitious number that appears too high to be reasonable,"[77] its allocation of labour between O&M and capital expenses is reasonable and consistent with past practice. YECL added that labour costs are distributed to O&M accounts or capital accounts depending on the nature of the work being performed by staff. YECL argued that UCG's suggestion that capitalizing 27 percent to 30 percent of labour would be more appropriate without any evidence as to where that number comes from or why it would be appropriate for YECL in the test period is, itself, arbitrary.

YECL also argued that UCG's suggestion that historical trends should be utilized to forecast the labour to be capitalized is illogical. More specifically, YECL stated that the amount of capital work being completed by YECL staff is significantly higher in the test period than it has been in the past, so it is to be expected that the percentage of labour being capitalized should be somewhat higher. YECL submitted that using historical trends to calculate the percentage of labour to capitalize would overstate the amount of labour allocated to O&M expenses and improperly increase the amount being paid by customers for O&M labour in the test period.

Finally, YECL argued that UCG's suggestion that the percentage of labour being capitalized should be compared to other utilities and a formal industry standard determined is yet another example where UCG is looking to spend ratepayer dollars on an expert to solve a problem that doesn't exist. YECL stated that its allocation of actual labour is already audited by its external auditors on an annual basis to ensure that it is appropriate. The amount of labour being capitalized by YECL is based on the exact circumstances of its own labour complement, so a benchmarking exercise would be of no value.

5.3.3.2 Views of the Board

The Board rejects UCG's recommendation to reduce the labour capitalization rate from 33 to 34 percent to 27 to 30 percent. The Board finds that whether YECL's capitalization rate is comparable or not to other utilities is irrelevant. If YECL staff are engaged in

[77] UCG Final Argument, paragraph 138.

more capital-related projects than other comparable utilities, then more should be capitalized, and vice versa. The capitalization rate should not be based on what other utilities are doing but on what YECL is doing and plans on doing in the test period. Further, the Board recognizes that UCG did not provide any evidence as to why its estimate was superior to YECL's estimate or even how it was determined.

The Board also rejects UCG's recommendation to order an independent study of YECL's capitalization policy. The Board is not persuaded that such a study is needed because UCG has not flagged any issues or submitted any evidence to suggest that YECL's current practices are insufficient. Further, the allocation of YECL's actual labour is audited by its external auditors on an annual basis to ensure that it is appropriate. Accordingly, the Board approves YECL's proposal for the capitalization of labour.

5.4 Pension matters

In the Application, YECL submitted that as a result of the required defined benefit pension plan actuarial valuations of assets and liabilities, pension funding requirements had changed as follows:

Table 6. **Pension funding requirements (funding period ending December 31)($000)**

Year	Defined benefit (annual lump sum)	DB special payments (annual lump sum)	Defined benefit total
2010	517	297	814
2011	517	297	814
2012	630	638	1,268

YECL submitted that the 2013 test period assumes the same defined benefit contribution rates as 2012. Since the next defined benefit pension actuarial evaluation will be completed as of December 31, 2012 to determine 2013 required funding, any required change to the 2013 defined benefit pension funding requirements will impact the defined benefit pension expense related to YECL's eligible northern-based staff.

In response to YUB-YECL-5, YECL submitted that the defined benefit pension actuarial evaluation as at December 31, 2012 (2013 actuarial report) had been completed in July 2013. As a result of the update, YECL revised the funding requirement from $1.268 million to $0.956 million. More specifically, this $0.203-million reduction was the result of current service payments being revised down to $0.605 million and special payments being revised down to $0.351 million.

In response to WL-YECL-12(f), YECL submitted a schedule showing the amounts it had incurred from 2008 to 2012 and the amounts it had forecast in the test period for its pension plans. More specifically, the schedule of amount incurred and forecast are reproduced in the table below:

Table 7. **Pension funding requirements (funding period ending December 31)($000)**

	Current service payments	Special payments	Total defined benefit payments	Defined contribution payments
2008	521	99	620	
2009	566	86	652	
2010	509	284	793	121
2011	543	303	846	162
2012	630	638	1,268	166
2013	630	638	1,268	172
2014	630	638	1,268	178
2015	630	638	1,268	184

In its update filing,[78] YECL further updated its 2013 defined benefit pension funding to $1.041 million. YECL stated that it had two employees transfer lump sum amounts out, resulting in a required transfer deficiency payment of $84,755.

YECL also requested a deferral account to flow-through increases or decreases to required cash contributions to the Applicant's defined benefit pension plan as a result of the required annual actuarial evaluations. YECL also has a defined contribution pension plan that applies to employees that were hired after January 1, 1997. YECL's contribution to the defined contribution plan is six percent.

5.4.1 Defined Benefit Plan Contributions

YECL's practice has been to include the full special payment, based on the cost-of-living adjustment being equal to 100 percent of the annual increase in CPI to a maximum of three percent, in revenue requirement.

5.4.1.1 Views of interveners

In argument, CW stated that YECL's defined benefit plan contains the following clause:

> The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous annual adjustments paid.[79]

CW added that the same clause is included in the CU Pension plan, which was submitted by the City as Exhibit C2-4 as an aid to cross-examination.

[78] Exhibit B-11, page 8 of 9.
[79] Undertaking # 2, Attachment 2, page 39 of 70.

CW stated that in Alberta there have been a series of pension proceedings to assess the level of special payments requirements for the CU pension plans and that in Decision 2010-189 related to the ATCO 2009 Pension Common Matters proceeding, the Alberta Utilities Commission (Commission, AUC) discusses the cost-of-living adjustment (COLA) provisions in the plan. More specifically, CW's argument pertaining to the pension proceedings in Alberta are summarized below:

> In Decision 2010-189, the Commission had stated:
>
> The Pension Plan was appended as Attachment I to UCA-ATCO-6. At pages 34 and 35 of the Pension Plan, sections 6.9(a) and 6.12(a) provide for the annual adjustment mechanism. Section 6.9(a) states:
>
> > The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the annual adjustment the Company will take into consideration annual percentage changes in the Consumer Price Index for Canada and any previous adjustments paid. [Company refers to Canadian Utilities]
>
> Section 6.12(a) contains similar language:
>
> > The annual adjustment will be as determined by the Company but will not exceed 3% per annum. In calculating the adjustment the Company will take into consideration the annual percentage changes in the Consumer Price Index for Canada and any previous adjustments paid. [Company refers to Canadian Utilities][80]
>
> In that same proceeding, the Alberta Office of the Utilities Consumer Advocate (UCA) had argued:
>
> > ... the Pension Plan provides ATCO Utilities with discretion in the setting of the COLA and that it did not have to automatically be set as a specific rate of increase based on CPI. In response to ATCO Utilities' position that a long standing administrative practice existed for determining COLA, UCA submitted that ATCO Utilities had improperly impaired the discretion that was allowed under the provisions of the Pension Plan. By adopting this administrative practice, ATCO Utilities had lost the ability to reduce COLA to assist with managing pension costs and the unfunded liability of the pension plan.[81]

ATCO had argued that its COLA practices were in line with industry practices.[82] ATCO also provided a legal opinion that indicated ATCO had "a longstanding administrative practice of granting adjustments equivalent to 100% in the increase in the CPI, up to the 3% cap."[83]

[80] Alberta Utilities Commission Decision 2010-189, paragraph 107-108.
[81] Alberta Utilities Commission Decision 2010-189, paragraph 110.
[82] Alberta Utilities Commission Decision 2010-189, paragraph 114.
[83] Alberta Utilities Commission Decision 2010-189, paragraph 115.

> The Commission had found that a change to the longstanding administrative practise of granting COLA equivalent to 100 per cent of the CPI is a possible means of mitigating the projected pension plan deficit. Further, the Commission had stated:
>
> A change to the ATCO Utilities long standing administrative practice of granting COLA equivalent to 100 percent of the increase in the CPI, up to the three percent cap, represents a possible means of mitigating a significant portion of the projected Pension Plan deficit. While ATCO Utilities have argued that there may be legal issues associated with a change to this long standing administrative practice, the Commission considers that these legal considerations are primarily a product of ATCO Utilities' own creation as a result of employee/pensioner communications and/or administrative practices that do not reflect the full discretion provided in the COLA provisions in the Pension Plan. The Commission considers that ratepayers should not bear any incremental pension funding costs which arise as a result of reduced Pension Plan flexibility with respect to annual COLA where it is demonstrated that such incremental costs prove to be unreasonable or imprudent in the circumstances. This is true particularly if current administrative practices prevented Canadian Utilities from reducing the COLA in order to reduce an unfunded liability when it may have been prudent to have done so in the circumstances.[84]

The Commission had considered that ATCO should have maintained its discretion in setting COLA, and then used that discretion to mitigate the plan deficits. In that decision, the Commission directed ATCO to:

> ... take such steps as may be required to ensure that the flexibility and discretion provided by the wording of the Pension Plan… may be fully exercised,[85] and
>
> ... prepare future revenue requirements forecasts of pension costs in a manner which reflects the flexibility and discretion provided by the wording of the Pension Plan…[86]…

In Decision 2011-391, the Commission maintained its view that use of the discretion available in the application of the COLA provision is an option to manage the unfunded liability:

> The Commission continues to view the discretion allowed by the DB Plan with respect to the annual COLA amount as an available tool to the pension administrator and Management Pension Committee in actively managing the DB unfunded liability in carrying out their fiduciary and contractual obligations. Further, the availability of that discretion and the exercise, or lack thereof, of that discretion is a relevant and material consideration for the Commission to take into account in determining the reasonableness of the pension expense which ATCO Utilities has requested be included in its respective revenue requirements and therefore customer rates. Also relevant is the need to maintain a competitive

[84] Alberta Utilities Commission Decision 2010-189, paragraph 118.
[85] Alberta Utilities Commission Decision 2010-189, paragraph 119.
[86] Alberta Utilities Commission Decision 2010-189, paragraph 120.

> pension plan as a key component of total compensation available to employees of ATCO Utilities.[87]

Further, the Commission had noted that there was a wide range of COLA provisions in use in comparators, and that the most common percentages of CPI were between 50 percent and 75 percent of CPI.

> The Commission has considered the information available on the record, including the positions taken by ATCO Utilities and the UCA which range from 100 per cent of CPI to 50 per cent of CPI respectively, up to a three per cent cap. The Mercer report analysis illustrates the wide range of COLA percentages used by DB pension plans for entities in the comparator group as of the date of the report in 2010. Some members of the comparator group set COLA at a two per cent minimum with any increase above that being done on an ad hoc basis while others tied COLA to CPI with a range from 50 per cent to 100 per cent of CPI as shown in Table 1 below. The most frequent COLA provision for the comparator group set COLA in the 50 per cent to 60 per cent of CPI range with the majority using CPI in the 50 per cent to 75 per cent of CPI range.[88]

Based on the entire record of the proceeding, the Commission had ordered:

> Based on the above considerations and analysis and subject to the directions below, the Commission finds that until the Commission otherwise directs, 50 per cent of Canada CPI up to the three per cent maximum permitted by the DB Plan represents a reasonable level for setting the COLA amount for the purposes of determining the pension cost amounts for regulatory purposes for all employees, including both retirees and active employees, which are components of revenue requirements or capital amounts for each of the ATCO Utilities.[89]

The issue was also reviewed in a Review and Variance application. In Decision 2012-077, the Commission had denied the ATCO application to review and vary Decision 2011-391. Further, the Alberta Court of Appeal had denied the ATCO appeal of the Pension decision[90].CW submitted that if the special payment was assessed based on the assumption of COLA being equal to 50 percent of the annual increase in CPI to a maximum of three percent, which it was not, YECL's special payment would decrease from $351,000 to $59,600. CW recommended the Board only allow an assumption of a 50-percent CPI provision to a maximum of three percent for the calculation of pension funding for the test period, which is consistent with the Alberta findings for pension funding with respect to the ATCO group of companies.

YECL responded that it had included an explanation of its historical practice of including in its revenue requirement the full special payment based on the cost-of-living adjustment being equal to 100 percent of the annual increase in CPI to a maximum of three percent in its response to Undertaking #3. YECL further submitted that its historical practice is reasonable and appropriate and should continue to be approved by the Board.

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[87] Alberta Utilities Commission Decision 2011-391, paragraph 83.
[88] Alberta Utilities Commission Decision 2011-391, paragraph 86 (footnotes omitted).
[89] Alberta Utilities Commission Decision 2011-391, paragraph 92.
[90] ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission), 2013 ABCA 310.

YECL argued that, while it acknowledges that the material put on the record by CW is a representation of what occurred in 2010 and 2011, the materials provided by CW do not provide the full story of what has occurred and continues to occur in Alberta. In addition, YECL submitted that CW's argument completely ignores the Mercer (Canada) Limited Total Compensation Review (Mercer Review) evidence filed by YECL as part of its response to Undertaking #3, which supports YECL continuing to include defined benefit payments based on COLA equal to 100 percent of the annual increase in the CPI to a maximum of three percent as being reasonable and prudent.

YECL further argued that CW's position also ignores the defined benefit pension plans of other comparable Yukon employers, such as the Government of Yukon, which has a fully indexed defined benefit plan, and YEC, which has a fully indexed defined benefit plan up to a maximum of three percent. In the case of YEC, YECL notes Board Order 2013-01 approved a revenue requirement that included pension funding based on COLA equal to 100- percent of the annual increase in the CPI to a maximum of three percent.

YECL added that it was important for the Board to understand that the ATCO Utilities have filed a leave to appeal on November 19, 2013 with the Supreme Court of Canada relating to Commission Decision 2011-391. As of December 16, 2013, this leave to appeal continues to be before the Supreme Court. In addition to the leave, YECL submitted that the ATCO Utilities have filed a 2013 defined benefit pension application with the Commission on December 6, 2013. This application includes additional evidence from that which was filed by the ATCO Utilities in 2010 and 2011, including the above-noted Mercer Review. The Mercer Review includes an analysis of salary, short-term and long-term incentives, pension, savings, benefits and perquisites. This type of study is also referred to as a “total compensation review”. The purpose of the review is to provide an independent market-based assessment of the ATCO Utilities', including YECL’s, total remuneration levels.

YECL stated that the Commission confirmed at paragraph 122 in Decision 2010-189, that "the COLA provision should be evaluated as part of the overall compensation available from a competitive employer who must also balance its long-term pension funding obligations as a regulated utility in a prudent manner." The focus of the Mercer Review is total remuneration as a whole rather than on each individual element. This provides a more accurate assessment of the competitiveness of the ATCO Utilities' total remuneration against its labour market competitors. It is inappropriate to compare individual elements of total remuneration on an isolated basis.

YECL submitted that this determination is consistent with Commission Decision 2009-151, where the Commission held at paragraph 96 that "its focus should be on total compensation and not on the details of the individual components. Total compensation includes consideration of employee pension and benefits in addition to base pay, STIP, LTIP, and perquisites."

YECL argued that it is reasonable for it to be able to fully recover 100 percent of its pension costs based on the enabling legislation and long established regulatory principles regarding recovery of prudently incurred costs. YECL stated that it is a basic

concept that for private ownership of utilities to be sustainable and serve customers well over the long term, they must have a reasonable opportunity to recover all of their prudently incurred costs. The potential denial of substantial real costs for an indefinite future will cause significant material harm to YECL.

YECL submitted that paragraph 122 in Commission Decision 2010-189 established that overall compensation provides the proper context for assessing pension costs. YECL argued that based on the Mercer Review evidence filed in this proceeding, the ATCO Utilities' total target remuneration, including YECL's, and including defined benefit pension payments based on COLA equal to 100 percent of the annual increase in the CPI to a maximum of three percent, is below the median compared to labour market competitors. It added that restricting defined benefit pension cost recovery to 50 percent of COLA costs deprives YECL of any opportunity to recover its prudently incurred costs. COLA at 50 percent of CPI results in both pension cost and overall compensation being below the median of the ATCO Utilities' comparators. YECL argued that this result is neither fair nor appropriate and results in rates that are unjust and unreasonable, and there is simply no support for this arbitrary action. To the contrary, recovery of the full COLA is supported by the evidence filed herein. YECL recommended that the Board allow full cost recovery of COLA in accordance with the calculations determined in the annual defined benefit actuarial valuations.

5.4.1.2 Views of the Board

The Board notes CW's submissions that the YECL's COLA adjustment is not in keeping with the Alberta Utilities Commission decision discussed at length above. Considering that the findings of the Commission on COLA adjustment are on the same pension plan in question in this proceeding, the Board reduces the COLA adjustment from 100 percent to 50 percent and orders YECL to adjust its defined benefit pension funding requirement forecast accordingly and to reflect these findings in the compliance filing.

5.4.2 Defined Benefit Deferral Account

YECL requested a deferral account to flow-through increases or decreases to required cash contributions to the Applicant's defined benefit pension plan as a result of the required annual actuarial evaluations. More specifically, YECL was seeking deferral account protection on both the current service and special payment portions of the contributions.

YECL submitted that, as explained in its response to YEC-YECL-10(a), between 2006 and 2012, defined benefit contributions have varied between a low of $0 and a high of $1,268,000. YECL further submitted that it is requesting deferral account protection for both the current service portion and the special payment portion.

YECL stated that approval of deferral treatment for both current service and special payments on its defined benefit pension plan would not result in a reduction to YECL's risk. In the prior test period, there was a three-year actuarial valuation in place in 2007 that covered the entire 2008-09 test period. Therefore, there was no need for a deferral account. However, due to changes in the regulatory environment, YECL must complete an actuarial evaluation every year in the current test period. This may result in either

increases or decreases to its funding requirements. Accordingly, YECL argued that the requested deferral account effectively keeps YECL's risk constant in relation to the 2008-09 GRA.

In support of its request, YECL noted that both Northland Utilities (Yellowknife) Ltd. and Northland Utilities (NWT) Ltd. have similar deferral accounts approved that cover all increases or decreases to required cash contributions to the defined benefit pension plan as compared to forecast. Additionally, while the matter has not yet been resolved, in its decision respecting the 2013-2014 GRA for ATCO Electric Ltd. Transmission, the Commission held that costs related to an updated actuarial defined benefit pension plan valuation are outside the control of ATCO Electric and are therefore not able to be reasonably forecast, and that forecasting differences could result in a material gain or loss.[91]

YECL reiterated that its proposed defined benefit pension plan deferral is reasonable and appropriate and should be approved by the Board as filed.

5.4.2.1 Views of interveners

In argument, YEC submitted that there is no precedent in Yukon for any of the new deferral accounts and YECL can provide few precedents from elsewhere to support application of these accounts in Yukon. More specifically, YEC submitted that YECL had noted that Northland Utilities (Yellowknife) Ltd. and Northland Utilities (NWT) Ltd. had similar deferral accounts. YEC argued, however, that although AUC Decision 2013-358 was noted by YECL as support for the deferral account, based on its review of the decision, it appeared to YEC that the deferral account was denied by the Commission.[92]

YEC further argued that the pension valuation as at December 31, 2012 was completed in July 2013, and defined benefit pension funding for 2013 as a result of this valuation would decrease O&M for 2013. Accordingly, YEC submitted that there is sufficient information to update 2013 revenue requirements in the compliance filing rather than flow these changes through to a deferral account. In summary, based on the factors discussed above and in the absence of any established current need for these new deferral accounts, YEC recommended that the Board not approve this deferral account.

In reply argument, YECL stated that YEC's reference to the Commission denying a similar deferral request in AUC Decision 2013-358 is incorrect. YECL submitted, as per paragraph 42 of YECL's Argument and page 99 of AUC Decision 2013-358, this matter has not yet been finally resolved by the AUC. YECL further submitted that the AUC did state that costs related to an updated actuarial defined benefit pension plan valuation are outside of the control of ATCO Electric and are therefore not able to be reasonably forecast, and that forecasting differences could result in a material gain or loss. YECL submitted that the evidence included in this application is consistent with these views and confirms the need for the requested deferral account. Accordingly, YECL reiterated

[91] AUC Decision 2013-358, paragraph 99.
[92] YEC Final Argument, page 16, footnotes 45 and 46.

its position that the defined benefit pension plan deferral is reasonable and appropriate and it should be approved by the Board as filed.

In reply, YEC reiterated its concern with the nature and number of new deferral accounts proposed by YECL in its 2013-15 GRA. YEC submitted that at a high level, it is very concerned that the proposed deferral accounts are forcing utility regulation down a path that essentially re-juggles the traditional and long-held apportionment of risk between the utilities and ratepayers and in essence forces ratepayers to take on more and more risk — with limited opportunities to benefit from undertaking the risk — while shielding the utilities from many risks that traditionally are borne by them.

YEC further submitted that with regard to all of the requested new deferral accounts, it is of the view that nothing has changed materially in the regulatory environment in Yukon to support the need for these extraordinary new risk-management mechanisms. In the absence of any established current need for these new deferral accounts, YEC recommended that the Board not approve at this time any of the three new YECL deferral accounts requested.

5.4.2.2 Views of the Board

The Board realizes that most of the volatility arises from special payments and that allowing a deferral on just the special payments is an option; however, the ranges for the 2008 to 2012 period, as illustrated in the schedule provided by YECL in response to WL-YECL-12(f), for current service payments and special payments, were $509,000 to $630,000 and $86,000 to $638,000 respectively. Although the volatility for the current service payments was less than that of the special payments, it was, in the Board's opinion, still significant. With the volatility noted, the Board recognizes that a deferral account for both the current service payments and the special payments would meet the criterion that "costs are not under the control of the company and are not reasonably forecastable."

With regard to the criterion to materiality, the Board is of the view that the amounts in question are material relative to the revenue requirement of the Applicant. More specifically, based on information provided in the updates filing,[93] the defined benefit funding requirements for 2013 would be just under two percent of the Applicant's forecast 2013 tariff — i.e. $1.041 million over $52.7 million.

Although the Board recognizes YEC's argument that approval of the deferral account reduces YECL's risk, the Board disagrees with YEC that this is detrimental to ratepayers. Defined benefit funding requirements will be inherently volatile since they are based on actuarial assumptions partial to swings in the financial markets. The market factors that drove the pension into a deficit could just as easily reverse and put the pension into a surplus position. If market forces move in the right direction, ratepayers will benefit from lower contributions. If market forces move in the wrong direction, ratepayers will be adversely affected through higher contributions. Whether future market events will be beneficial or detrimental to the pension plan are not known to the Board, or in the Board's opinion, anyone else. By requesting the defined benefit

[93] Exhibit B-11, Section 10, page 8

pension requirement deferral account, YECL has signaled that it does not want to speculate on the financial markets. In the Board's view, neither does the ratepayer.

Accordingly, the Board hereby approves the defined benefit pension deferral account for both special payments and current service payments for the 2014 and 2015 test years.

5.4.3 Defined Contribution Plan Contributions

In argument, YECL submitted that the defined contribution plan is six percent and that this contribution is reviewed annually by management as part of its review of the compensation package offered by the Applicant. YECL further submitted that no changes to this previously approved contribution rate are forecast during the test period.

No interveners commented on the defined contribution plan.

5.4.3.1 Views of the Board

The Board finds that the six-percent contribution rate for the defined contribution plan is reasonable and approves the defined contribution plan as requested.

5.4.4 Non-Labour Costs

YECL forecast non-labour costs in two parts: (i) ongoing operational and administrative activities (O&A), and (ii) new programs or projects. In the Application, YECL explained that ongoing O&A are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.

5.4.4.1 Non-Labour Inflation

For non-labour costs, YECL proposed an inflation rate of 1.9 percent for 2013, 2.0 percent for 2014, and 2.1 percent for 2015. YECL submitted that the 2013 inflation forecast was based 50 percent on forecast Alberta inflation and 50 percent on forecast Yukon inflation. YECL stated, however, that the 2014 and 2015 inflation forecasts had been based 50 percent on forecast Alberta inflation and 50 percent on forecast British Columbia inflation since no forecast of Yukon inflation was available for those years.

In response to YUB-YECL-18, YECL provided the raw data used to calculate its non-labour inflation forecasts for the test period. With regard to its method of basing non-labour inflation on the forecast rates of two jurisdictions, YECL stated that this methodology is consistent with the methodology ordered in Board Order 2009-02. Further, YECL submitted that it was appropriate to base its non-labour inflation forecasts on forecast Alberta inflation because YECL purchases a significant amount of goods and services from Alberta. With respect to British Columbia, YECL submitted that it was reasonable due to its proximity to Yukon.

No interveners commented on YECL's non-labour inflation forecasts.

5.4.4.1.1 Views of the Board

The Board has reviewed the calculations used by YECL to determine the non-labour forecasts and finds them to be reasonable. Further, the Board is satisfied with the

rationale for using forecast Alberta and British Columbia inflation as a proxy for Yukon inflation. The Board finds that the non-labour inflation forecasts have been thoroughly tested in this proceeding and are reasonable. The Board approves the non-labour inflation forecasts for the test period as requested.

5.4.4.2 UCG Request to Reduce Non-Labour O&M Per Customer

In responses to Undertaking #13,[94] YECL provided a table showing O&M expense on a per customer basis. More specifically, the table is reproduced below:

Table 8. **Operations and maintenance expenses per customer**

	2008	2009	2009	2010	2011	2012	2013	2014	2015
	Actual	Approved	Actual	Actual	Actual	Actual	Forecast	Forecast	Forecast
Production	1,596	1,583	1,647	1,593	1,849	1,978	2,169	2,477	2,550
Distribution	2,336	2,440	2,638	2,662	2,659	3,281	3,141	3,215	3,376
General	148	170	142	150	141	178	159	162	165
Public Information	105	133	122	104	111	137	151	155	159
Customer Accounting	1,857	1,966	2,054	2,006	1,922	2,016	2,248	2,318	2,316
Administration and General	2,551	2,534	2,870	3,110	3,117	3,468	3,866	3,992	3,940
Total Operations and Maintenance Expenses	8,593	8,826	9,474	9,625	9,799	11,059	11,735	12,319	12,507
Number of Customers	15,339	15,562	15,596	15,884	16,272	16,702	17,028	17,306	17,597
Non-Fuel Operating and Maintenance Cost per Customer	560.23	$567.15	$607.44	$605.95	$602.20	$662.13	$689.18	$711.86	$710.74
Year-over-Year % Increase from 2009 Approved			8%	0%	-1%	10%	4%	3%	0%
Cumulative % Increase from 2009 Approved			7%	7%	6%	17%	22%	26%	25%

5.4.4.2.1 Views of the interveners

In argument, UCG submitted that Yukon utilities need to adopt an overall cost-conscious culture and follow a formal cost optimization program. More specifically, UCG submitted that both YECL and YEC need to devise new strategies to control rising costs and show the Board and stakeholders that they are seriously working on limiting rate increases. UCG stated that if YECL does not have a clear, defensible, systematic plan

[94] Exhibit B-15.

to manage operating costs, the Board should not approve requested increases in controllable revenue requirements.

UCG further submitted that rather than just cutting costs, YECL should be directed to look at doing more with the same amount of money or doing the same with less. More specifically, UCG provided a few suggestions, including restricting staff travel and reducing training budgets. UCG further recommended that the Board direct YECL to look at more impactful business-integrated programs such as undertaking contract reviews, re-opening supplier negotiations or rationalizing one or more functions. It pointed to Undertaking #13 as evidence of the rapid escalation of costs.

UCG recommended that the Board direct YECL to reduce O&M costs per customer by 10 percent in each of the test years and establish a clear plan of actions that will reduce O&M costs.

In reply argument, YECL submitted that UCG's recommendation to reduce O&M costs per customer by 10 percent is without evidentiary support and arbitrary. YECL submitted that the Board should reject UCG's recommendation.

5.4.4.2.2 Views of the Board

The Board has reviewed Undertaking #13. However, this table is not sufficient to support UCG's recommendations. UCG did not file any evidence in support of its position nor did it lay the groundwork by way of cross-examination for its recommendations. Simply put, there is no evidentiary basis which supports UCG's recommendation to order a reduction in YECL's O&M per-customer costs. Accordingly, the Board rejects UCG's recommendation to reduce O&M cost per customer by 10 percent.

5.4.5 Affiliate Costs

In the Application, YECL submitted that it outsources certain major administrative functions to affiliate companies, such as ATCO Electric, to take advantage of the economies associated with the scope and scale of services available from a larger utility. YECL stated that the costs of these services are based on a fully allocated cost methodology that does not contain any element of profit or return.

5.4.5.1 Views of the Interveners

In argument, UCG submitted that the Financial Reporting and Regulatory Support provided by ATCO to YECL appears to have no limits. Further, UCG noted that YECL stated that in 2012, ATCO Electric started charging YECL for the costs of an Edmonton-based corporate accountant as well as 0.5 FTE Manager. This added $235,000 to the costs in 2012 and an additional $166,000 is being added to the 2013 budget.

UCG further submitted that there is no evidence on the record justifying the increasing allocation of affiliate costs to YECL. UCG stated that Financial Reporting and Regulatory Support-related cost transfers from ATCO included in the test period revenue requirements should be capped at the level currently approved for recovery in rates.

5.4.5.2 Views of the Board

The Board has already addressed the issue of FTE complements in Section 5.1 of this decision.

With regard to UCG's recommendation that Financial Reporting and Regulatory Support related cost transfers from ATCO be capped in the test period revenue requirements at the current levels, the Board finds UCG has not provided adequate argument or evidence as to why YECL's forecast amounts are imprudent or aggressive. The Board does not know what effect capping these costs would have on the operations of YECL. Accordingly, the Board rejects this recommendation.

With the exception of affiliate-related issues addressed in other parts of this decision, the Board approves YECL's requested affiliate transactions because it finds that the forecast for these costs is reasonable for the test period.

5.4.6 Discontinuance of Third Party Distribution Line (Property) Insurance

In the Application, YECL submitted that historically, it had purchased property insurance for distribution lines with a $1.5-million limit and a $1-million deductible. The cost of this insurance is approximately $127,000 per year. Based on its claim history and the corresponding costs, YECL requested approval to discontinue purchasing third party distribution line insurance at the end of the 2013-14 insurance period. On a go-forward basis, insurable losses during construction or operations would be charged to the reserve for injuries and damages fund.

No interveners commented on this request.

5.4.6.1 Views of the Board

The Board agrees with YECL that, given its limited claim history, the third party distribution line insurance may be eliminated. Accordingly, the Board grants this request.

5.5 Issues raised by interveners

5.5.1 UCG Recommendation for the Board to Engage an Independent Expert

In argument, UCG recommended that the Board engage an independent expert to assist in the benchmarking of the cost components of YECL and YEC operations to other utilities within North America. UCG submitted that the Board and interveners require this information to assess the utilities' performance relative to industry standards and to assist the Board in the important task of adjudicating the prudency of utility decision-making.

In reply argument, YECL submitted that to engage in such a benchmarking exercise would add additional administrative burden and expense to ratepayers, with little to no value. Further, YECL submitted that the Board already engages technical experts with knowledge and experience related to utility revenue requirement issues to assist in reviewing the evidence provided by the utilities in order to assess reasonableness and prudence. As well, the specific nature of the Yukon interconnected system is unique in

that there are a relatively small number of customers, a high degree of isolation, and a large geographic area with a harsh environment. YECL stated that finding comparable utilities that operate in an environment with such characteristics would be difficult, if not impossible. In addition, such a benchmarking exercise is not needed for the Board to fulfill its mandate.

5.5.1.1 Views of the Board

The Board and interveners test the evidence filed by each utility by way of information requests and questioning at a hearing. Interveners may also hire technical experts to assist them in preparing their cases and provide evidence during a proceeding. In addition, the Board has the assistance of technical staff in reviewing the evidence filed by a utility. Further, the Board recognizes that Yukon utilities operate in an environment that is unique to the rest of North America and that any results from a benchmarking of other North American utilities is quite unlikely to result in relevant benchmarks. Accordingly, the Board rejects this recommendation.

6 TAXES OTHER THAN INCOME

YECL included the following for property taxes in its application[95]:

Table 9. **YECL Taxes other than income**

	2008 Actual	2009 Actual	2010 Actual	2011 Actual ($000)	2012 Actual	Test Period 2013	2014	2015
Property Taxes	231	239	230	235	250	257	265	273

YECL noted that property taxes are annual paid to communities for office buildings, generation facilities, substation properties and power lines. Increases in forecast property taxes were due to capital work on the downtown Whitehorse office building, the Fish Lake unit #1 building, as well as inflation[96]. YECL provided a further breakdown showing that the annual forecast inflation increase was $5,000, with forecast increases[97] due to capital being $2,000 for 2013, $10,000 for 2014, and $18,000 for 2015.

In its argument, UCG noted that YECL was collecting in its rates $254,000 per year, based on Board Orders 2009-2 and 2009-5. UCG argued that the amounts collected for the years 2009 to 2012 exceeded the actual amounts paid by YECL for property taxes by $62,000,[98] and therefore, YECL should not be granted any increase in property taxes for the test years.

[95] YECL Application, page 6-1.
[96] YECL Application, page 6-1.
[97] Information Responses YUB-YECL-35.
[98] UCG Final Argument, paragraphs 150 and 151.

In its reply, YECL noted in its response to UCG-YECL-22(c) that for 2013, property taxes actually paid by YECL exceeded the 2012 actual property taxes by $23,254[99].

6.1 Views of the Board

The Board notes that YECL's response to UCG-YECL-22(c) shows that 2013 actual property taxes exceed the 2013 forecast for property taxes by $16,254.67. In its reply argument YECL also stated that it "anticipates that property taxes for the test period will be greater than the original forecast"[100].

The Board accepts the submissions of YECL with regard to property taxes and notes that on a forecast basis sometimes the actual amount may be greater than forecast — as in 2013 — and sometimes the actual amount may be less — as in the years 2009 to 2012, as submitted by UCG. This is the nature of prospective rate-making. Therefore, the Board accepts the forecasts for property taxes — taxes other than income — as filed by YECL.

7 DEPRECIATION

YECL included the following for depreciation expense[101]:

Table 10. **YECL Depreciation Expense**

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Test Period 2013	2014	2015
				($000)				
Depreciation Expense	3,181	3,446	3,683	4,129	4,192	6,570	7,509	8,569

Depreciation expense for the years 2008 to 2012 were calculated using the Board-approved depreciation parameters from YECL's last GRA. For the test years (2013 to 2015) in this application, YECL used the lifespan analysis (similar to hydro generation) for each of its diesel generation locations. YECL further added that the reinstatement of a provision for future removal and site restoration (FRSR) is the primary reason for the material increase in depreciation expense.

YECL also replied that with no evidence or argument countering the methods used by Gannett Fleming the life parameters submitted in this GRA should be approved as filed.

[99] Information response UCG-YECL-22(c), where actual property taxes paid for 2013 were $273,254.67 versus the 2013 forecast from page 6-1 of the application of $257,000.
[100] YECL Reply Argument, paragraph 80.
[101] YECL Application, page 7-1.

7.1 Future Removal and Site Restoration (FRSR)

YECL in its argument stated:

> … the Depreciation Study has identified a material and growing deficiency in Yukon Electrical's net negative salvage reserve. This growing deficiency, together with the need to send the correct price signals to today's consumers, as opposed to a distorted price signal, to tomorrow's customers has led Yukon Electrical to request an end to the pause in Yukon Electrical's historical practice of including net negative salvage in its depreciation rates.[102]

YECL listed a "number of significant changes since Board Order 2009-02 that support the reinstatement of FRSR into depreciation expense:[103]

> 1. Sending the right price signal to customers especially now since diesel generation is on the margin. This correlates with the direction given by the Board in Board Order 2010-13. Related to proper price signals is the DSM program which will promote energy conservation and result in lower energy consumption.
>
> 2. YECL is falling behind in its required recovery of the funds for future removal of assets. YECL stated that its FRSR deficiency has grown significantly to over $12 million. The FRSR draw down was approximately 6.2 percent while the actual retirement of assets was approximately 3 percent. The FRSR is drawing down at approximately twice the retirement rate for assets. YECL added that older vintage assets are now three-years closer to expected retirement, providing less time for these vintages to recover the FRSR deficiency and that the inclusion of FRSR like costs is a widely accepted practice throughout Canada and North America.
>
> 3. YECL cited BCUC Order G-44-12 regarding FortisBC Energy's (FEU) 2012-2013 GRA, whereby that Commission accepted FEU's proposal of providing negative salvage in rates during the test period. YECL noted that the BCUC approved a different approach to net salvage for FEU than it had approved for BC Hydro.

YECL concluded this section of its final argument by stating:

> In other words, Yukon Electrical does not stand to gain from the reinstatement of net salvage and is motivated rather by sending the appropriate price signals to ratepayers and avoiding intergenerational inequities.[104]

In reply argument, YECL interpreted the UCG statement for a phased-in approach to negative net salvage as agreement with YECL's proposed net salvage parameters[105].

YECL countered YEC's argument by stating that sending correct price signals is not exclusively an exercise limited to Phase II deliberations on revenue-to-cost ratios and

[102] YECL Final Argument, paragraph 51.
[103] YECL Final Argument, paragraphs 55-59.
[104] YECL Final Argument, paragraph 60.
[105] YECL Reply Argument, paragraph 81.

that no party has put evidence on the record that the reinstatement of net negative salvage would result in costs that are not just and reasonable[106].

7.1.1 Views of interveners

Several interveners opposed the reinstatement of FRSR by YECL.

In argument, UCG stated that it did not have evidence to challenge the asset service lives and depreciation determined by the methods used by Gannett Fleming. However, UCG challenged whether a phased-in approach is useful[107]. UCG added[108] that the decision to re-implement FRSR was made by YECL management as noted in response to YUB-YECL-80(a) in which YECL stated:

> Gannett Fleming was also asked to research and provide an assessment of the reasonableness of including a request for the re-instatement of net salvage percentages into the depreciation rate calculations.

In its argument, UCG contended that the impact of allowing FRSR back into rates is significant[109], and that the liability associated with the negative salvage liability is assumed to still be below the $2-million threshold[110] established by the Board in Board Order 2009-02, and therefore, YECL should not record provisions for FRSR.

In reply, UCG stated:

> … YECL has failed to provide enough evidence regarding discernable end-of-life and salvage values of abandoned or retired equipment to allowing (sic) the proposal to be implemented.[111]

YEC argued that YECL, for FRSR, has failed to provide any compelling rationale to deviate from prior Board direction in this regard[112] and has not established any material change in circumstances since Board Order 2009-02 was issued that would cause this issue to be re-examined[113].

YEC added that the Board set a clear criterion for reviewing this issue, and that criterion was when the fund balance approached $2 million, and the response to YUB-YECL-80(b) shows the 2012 FRSR balance as $4.395 million.[114]

Further, rate design principles, rather than revenue-requirement matters were behind the reasons given by YECL in support of the reinstatement of FRSR,[115] and as such, YEC argued that rate design principles are beyond the revenue requirement matter.

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[106] YECL Reply Argument, paragraphs 85 and 86.
[107] UCG Final Argument, paragraph 165.
[108] UCG Final Argument, paragraph 167.
[109] UCG Final Argument, paragraph 169 and Exhibit B-12 where the change in depreciation rates was calculated to be $5.93/month for a typical residential customer.
[110] UCG Final Argument, paragraph 174.
[111] UCG Reply Argument, paragraph 39, the proposal refers to FRSR.
[112] YEC Final Argument, page 4.
[113] YEC Final Argument, page 5.
[114] YEC Final Argument, page 5.

YEC continued by stating that the account has been drawn down by just over 6.2 percent over the past three years, the balance in 2012 is sufficient to address any planned retirements going forward, and YECL has not demonstrated it would be harmed by not having the fund re-activated[116].

In reply argument, YEC said that allowing YECL to reinstate the FRSR would treat ratepayers differently when dealing with Crown versus investor-owned utilities and added that arguments in support of the reinstatement of the FRSR based on diesel being on the margin, and the implementation of DSM measures are without merit[117].

LE supported the arguments brought forward by YEC.[118]

7.1.2 Views of the Board

In response to CW-YECL-30, YECL showed that without the reinstatement of FRSR, the depreciation expense for each of the test years is significantly lower. The following table shows the net reduction in depreciation expense with FRSR removed:

Table 11. **Change in Depreciation Expense with FRSR removed ($000)**

	Test Period		
	2013	**2014**	**2015**
General Provision	(1,493)	(1,619)	(1,846)
Amortization of differences	(473)	(473)	(473)
Vehicle Depreciation Capitalized	0	0	0
Total Change in Depreciation Expense	(1,966)	(2,092)	(2,319)

Clearly, the inclusion of FRSR in depreciation is a material matter.

In response to UCG-YECL-24(a), YECL provided a list of eight electric distribution utilities that include net salvage within their depreciation rates. Of that list, two are Crown corporations (ENMAX, Manitoba Hydro) and three are YECL affiliates [ATCO Electric, Northland Utilities (NWT) Ltd., Northland Utilities (Yellowknife) Ltd.].

In the same response, YECL provided an additional list of 11 regulated utilities — transmission, gas, pipeline — that include net salvage in their depreciation calculations.

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[115] YEC Final Argument, page 5. YEC noted that the reference to Board Order 2010-13, a Joint Phase II Rate Application was used out of context in this proceeding and that the focus on depreciation and accounting should be in the context that the costs are just and reasonable.
[116] YECL Final Argument, page 5.
[117] YEC Reply Argument, page 4.
[118] LE Reply Argument, page 1.

In response to UCG-YECL-25, YECL provided a list of 11 utilities that use an alternative mechanism for the recovery of costs of retirement. The majority of the utilities, but not all, in that response were Crown corporations.

In response to YUB-YECL-90 (b), YECL responded “no” to the question: Do accounting guidelines, MFRs or other rules or regulations delineate the use of depreciation parameters and FRSR policies based on the type of ownership — Crown versus private?

YECL stated the following regarding International Financial Reporting Standards (IFRS):

> I would suggest one is a tolerance to not include net negative salvage. Secondly, I would suggest that Crown corps for some reason, and I won't even try to speculate as to why, are less willing to have differences between the regulatory ledgers and their financial reporting ledgers. In other words, most of the Crowns have looked at the standard 16 of the IFRS and said "That does not allow inclusion of the net salvage in the rate calculation; therefore, we're not going to even apply for it," whereas most investor-owned utilities have a larger concern with the appropriate recovery of the total service value of assets.

And

> The IFRS standard says that you should not recover in the depreciation rates, rather you should recover in the year of occurrence for financial reporting purposes.[119]

Based on the above, the Board is not persuaded by YECL that the direction in Board Order 2009-02 should be changed. The Board is of the view that not including FRSR in depreciation rates is an acceptable practice, and that this exclusion of FRSR complies with IFRS, standard 16. The Board also took note of the testimony of YECL that it is not harmed if FRSR is not included in depreciation rates. Accordingly, YECL is not to record FRSR amounts in its depreciation rates. Further, the accumulated amount for net negative salvage is to be shown as a liability and reduced as salvage costs are incurred. YECL is to inform the Board and interested parties when the balance for this liability account reaches $2 million.

7.2 Lifespan Analysis

To support the new depreciation parameters, YECL provided a depreciation study applicable to plant in service as of December 31, 2011, as Attachment 1 to Section 7 of its Application. YECL proposed a lifespan analysis for the treatment of diesel generation plant.

[119] November 4, 2013 transcript, page 39, lines 10-20 and transcript volume 1November 4, 2013 transcript, page 40, lines 4-7.

The lifespan analysis was described as follows[120]:

> 11 A. MR. KENNEDY: Certainly. The use of a
> 12 lifespan analysis says we look at both the life of each
> 13 account, or the asset groupings, on the basis of a physical
> 14 or life estimation of that asset. Well, there is some
> 15 economic factors in there; for example, technological
> 16 obsolescence of specific equipment would be considered in the
> 17 general life estimation of an asset -- that Iowa curve, if
> 18 you will.
> 19 The use of a lifespan says: Well, overriding
> 20 the physical life and things we look at for each asset group,
> 21 we look at the economic factors of the facility as a whole.

7.2.1 Views of the Board

The Board notes that, with the use of lifespan analysis, the assets are not just looked at in terms of physical life, but also in terms of economic, technical or environmental factors that can limit or constrain the life of the asset. The Board is of the view that when a utility contemplates the acquisition of an asset such as a diesel generation unit, the utility looks at the economic life of the asset when it undertakes a cost-benefit analysis. Among other factors that the utility considers when it contemplates acquisition of the asset is whether the cost-benefit analysis is positive. All other factors being equal, the utility will operate that asset until a potential better option becomes available. If a potential better option does become available, the disposition of the existing asset will be factored into the cost-benefit analysis of the potential better option. Thus the termination of the economic life of the existing asset is determined at the time the potential better option is available.

The response to YUB-YECL-84(a) describes the process used to determine a best fit curve for a particular asset. It states on page 2:

> While this process begins with the determination of a best fit curve determined through the calculation of the residual measures, the statistical fitting process does not provide any weighting of the observed life table data points. Therefore, the statistical best fits are only used as a starting point for the remainder of the curve fitting process, in order that the analyst can place appropriate weighting on the various segments of the observed life table.

Considering the above, the Board is of the view that the forecast depreciation for any asset or asset class for any year is an estimate; that factors can change the estimated lives of assets, and the exact life of an asset is not known until the asset is actually retired. Thus, to the Board, taking an estimate of the physical life of an asset and superimposing on that estimate another estimated constraint due to other factors does not add certainty to the depreciation estimate.

[120] November 4, 2013 transcript, page 49, lines 11-21.

Further, in response to CW-YECL-33(c), YECL stated that “In total, the inclusion of the lifespan approach has a less than $50,000 impact on the depreciation expense applied to the recovery of the original cost.”

YECL provided the following response to a question during the hearing regarding the lifespan analysis[121]:

> A. MR. KENNEDY: I think you're asking is a $50,000 change caused by the move to lifespan material in the scheme of revenue requirement inclusion in excess of five or $6 million? I would view that to be not material, but that's my own opinion. Obviously every dollar counts when it's included in revenue requirement, but I think you do the right thing and take the right approach, an impact of $50,000 on the overall depreciation expense is relatively minor.

Given that a change to the lifespan analysis does not bring any more certainty to the estimate for depreciation expense, that the amounts are immaterial, and that any early retirement values should be considered when an alternative to an existing asset is being contemplated, the Board rejects the use of lifespan analyses as proposed by YECL and directs YECL to revert to the previous depreciation method for diesel generation when it provides its compliance filing.

7.3 Depreciation Deferral Account

YECL requested approval for a deferral account to allow it to change depreciation parameters, as necessary, and flow-through the impact to customers of such changes during the test period. YECL stated that the requirement to review its depreciation parameters annually and implement new depreciation rates if necessary is part of IFRS. The need for the deferral account is to account for new information or events. YECL added that its intent is to harmonize IFRS and regulatory accounting and avoid the administrative burden of maintaining two sets of financial records.

A description of the process to determine whether a change in depreciation parameters is required[122] was provided in the Application. The process included an analysis of comparing actual retirements versus predicted retirements. If a significant change is observed over a two- to three-year period and is not due to non-typical transactions, then an analysis of actual gross salvage and cost of retirement versus predicted gross salvage and costs of retirement to determine if a change in net salvage parameters are warranted.

In terms of a deferral account for depreciation, UCG noted that YECL could not identify any comparable utilities that have deferral accounts for depreciation parameters approved by a regulator[123].

[121] November 4, 2013 transcript, page 52, lines 18-25.
[122] YECL Application, pages 7-2 to 7-4.
[123] UCG Final Argument, paragraph 184.

YECL argued for the approval of a deferral with respect to changes in depreciation rates, as it:

> … would promote regulatory efficiency as it will assist in the harmonization of IFRS and regulatory accounting thereby avoiding the administrative burden of keeping two sets of financial records in respect of depreciation[124].

YECL added to its argument:

> While the update to the depreciation parameters for regulatory purposes could wait until Yukon Electrical's next GRA is filed, the delay would create a situation where Yukon Electrical would be managing two separate sets of books for property plant and equipment.[125]

7.3.1.1 Views of the Board

The Board took note of the response to CW-YECL-31(b), in which YECL confirmed that none of the YECL affiliates have a deferral account for depreciation parameters and in response to YUB-YECL-12(d), YECL stated it is not aware of any similar deferral accounts used by other regulated utilities in Canada.

Further in argument, YECL stated that it could wait to update its depreciation parameters until its next GRA, but it would have to manage two sets of books for property plant and equipment.

Based on the evidence of YECL, it can take several years to note material changes to depreciation parameters and to determine if such changes are an aberration or the start of a new trend. This analysis is likely to extend beyond the test period of any application provided by YECL. Further, the Board finds certain positions of YECL difficult to reconcile. On the one hand, YECL is perfectly willing to maintain a separate set of books and deviate from IFRS by including FRSR in depreciation rates, and yet argues that there is a burden to managing these books if a deferral account for depreciation parameters is not allowed. In addition, the use of such a deferral account does not comply with IFRS. The Board is of the view that to accept changes to depreciation parameters after a decision on the test period has been made would violate the prospective nature of rate-setting in Yukon. Therefore, the Board denies YECL's request for a deferral account on depreciation parameters.

[124] YECL Final Argument, paragraph 61.
[125] YECL Final Argument, paragraph 62.

8 RETURN ON RATE BASE

YECL included the following in Return on Rate Base[126]:

Table 12. **YECL Forecast Return on Rate base**

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Test 2013	Period 2014	2015
				($000)				
Return on Rate Base	3,163	4,191	4,071	4,266	4,642	5,308	6,255	7,003

It was noted by YECL that increase in return on rate base between the years 2008 to 2012 were mainly due to growth in rate base through capital additions. The increases in the forecast years 2013 through 2015 were primarily due to growth in rate base due to capital additions and the requested increase in the common equity ratio.

8.1 Cost of capital

On page 8-5 of its application, YECL has requested its ROE be linked for the 2013 to 2015 test years to the British Columbia Utility Commission (BCUC) benchmark rate of 8.75 percent plus a risk premium of 0.46 percent, giving a total requested ROE of 9.21percent. YECL submitted that the risk premium of 0.46 percent is consistent with the 0.46 percent risk premium approved in Board Order 2009-02. YECL asked that this premium be maintained for regulatory efficiency. YECL added that since the BCUC Generic Cost of Capital (GCOC) benchmark return on equity is subject to an annual adjustment mechanism (AAM), it is requesting a deferral account for ROE for the 2014 and 2015 test years.

No parties disagreed with the use of the BCUC benchmark rate of 8.75 percent Views diverged with respect to adding a premium to the BCUC benchmark rate.

UCG noted that the application of a risk premium over the Alberta benchmark ROE for YEC's 2012-13 GRA was rejected by this Board[127].

Further, UCG noted that in Board Order 2009-02 the risk premium allowed for YECL was set at the midpoint of the risk premiums between FortisBC and YEC.

UCG requested the following[128]:

> … UCG submits that the Board should establish YECL's capital structure with a 38.5% equity component with a related return on equity equal to the 8.75% established as the BCUC Generic Cost of Capital benchmark. While it is difficult to speculate what adjustment, if any, might be made to cost of capital of other

[126] YECL Application, page 8-1.
[127] UCG Final Argument, paragraph 213.
[128] UCG Final Argument, paragraph 224.

> regulated utilities in Phase II of the BCUC Generic Cost of Capital proceeding, the addition of a ROE risk premium should fully capture any possible necessary adjustment to YECL's capital structure and ROE to recognize any differences between YECL and the benchmark utility determined by the BCUC.

YEC argued[129] that the BCUC GCOC benchmark plus the addition of a risk premium of 0.46 percent is consistent with that previously approved by this Board for YECL in Board Order 2009-02.

YECL argued that its approach to return on equity is "wholly consistent with the approach being taken in BC."[130] YECL continued by stating that "Yukon Electrical's business and financial risks remain largely consistent with those assessed by this Board in 2008 as part of its 2008-2009 GRA." YECL added that it still supported the evidence of Ms. McShane and the stand-alone principle in determining equity thickness. YECL acknowledged that "its business risks are somewhat lesser than those of the YEC"[131].

In reply argument, UCG said there were two pillars to YECL's submissions. The first was the use of the most recent BCUC GCOC decision. "The second [was] the use of expert evidence introduced in proceedings of over 5 years ago to support conclusions about YECL's current business position in the market"[132].

It was submitted by UCG that, while benchmarks in other jurisdictions can be used, Yukon utilities cannot be allowed to make their own adjustments to the benchmark capital structure and returns.[133] UCG added that the BCUC GCOC only provided a formula to establish capital structure and rate of return on equity for a low risk utility — in this case, Fortis Energy. UCG stated that YECL did not attempt to compare itself to or assess its standing relative to Fortis Energy. UCG added that there is insufficient evidence in this proceeding concerning the differences in the business risk profile of YECL and the BCUC benchmark utility.

YEC replied:

> YECL asserts that it has "taken the current BCUC benchmarks and employed the same approach the YUB itself employed in Decision 2009-02 to adjust those BCUC benchmarks to bring them in line with Yukon experience"; however, there is no prior Yukon precedent for looking to BCUC as a benchmark to determine capital structure. BCUC (and AUC) decisions have only been relied upon in the past to determine benchmarks for ROE.[134]

8.1.1 Views of the Board

In Board Order 2009-02, the Board made its views known regarding generic cost-of-capital models. The Board set out three questions that need to be answered in relation to applicable generic cost-of-capital models and risk premiums:

[129] YEC Final Argument, page 6.
[130] YECL Final Argument, paragraph 67.
[131] YECL Final Argument, paragraphs 68-72.
[132] UCG Reply Argument, paragraph 40.
[133] UCG Reply Argument, paragraphs 41, 43 and 45.
[134] YEC Reply Argument, page 5.

(1) Which generic cost-of-capital model should be used and from which jurisdiction?

(2) Should a risk premium be applied?

(3) What risk premium should be applied to YECL?

YEC was correct in its reply argument that the precedent and practice of this Board is to use a benchmark from another jurisdiction (chiefly British Columbia) and that benchmark is only used to determine the return on equity, not the equity thickness. At the time of Board Order 2009-02, the BCUC benchmark utility was FortisBC. For the most recent BCUC decision, the benchmark utility is Fortis Energy.

Regarding the question on the application of a risk premium, in Board Order 2009-02, the benchmark utility was FortisBC and evidence had previously been submitted regarding the comparability of the BCUC benchmark utility to YEC. Appendix A, Reasons for Decision, attached to Board Order 2005-12, stated the following[135]:

> YEC is requesting that an appropriate risk premium would be 52 basis points, which is midway between the FortisBC risk premium of 40 basis points, and Pacific Northern Gas risk premium of 65 basis points (Application, page 8-4 to 8-6). Table 8.1 on page 8-6 of the Application provides a table showing the calculation in detail of the requested return on equity for YEC. (Page 43)
>
> …
>
> Return on equity was reviewed through Intervenor and Board staff IRs, as well as during cross examination of the YEC panel in the hearing. (Page 44)
>
> …
>
> Board counsel cross examined the YEC panel on relative risk of YEC compared to peer utilities, such as YECL, FortisBC and PNG in an effort to understand where YEC fits into the risk premium spectrum (T5:931 to 935). YEC accepted that they are less risky than PNG, but argued they are more risky than FortisBC due to the inter-tie with other utility networks, which allows it to generate less electricity and purchase more of its demand when needed. (Page 44)

And

> **Determination**
>
> The Board is of the opinion that the rate of return on common equity that YEC is requesting is reasonable, given their level of risk in relation to other utilities within their peer group. Using the BCUC automated adjustment mechanism as a proxy of rate of return on equity does not impose a precedent in the Yukon, and is an expedient and means of determining return for the current one year period. As for the issue of risk premium, the Board agrees that YEC likely falls somewhere between PNG at 65 basis points, and FortisBC at 40 basis points. To ensure that

[135] Appendix A to Board Order 2005-12, YEC 2005 Revenue Requirements, October 18, 2005, pages 43, 44 and 45.

> there is sufficient forecast risk within the revenue requirement model, YEC should be at risk for their forecasts of load, OM&A and capital expenditures. (Page 45)

The Board agrees with the submissions of UCG that no assessment has been provided within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear.

The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.

8.1.2 Automatic Adjustment Mechanism (AAM)

In its Application, YECL "is requesting a deferral account for 2014 and 2015 to flow through any change to the 8.75% ROE resulting from the AAM."[136]

LE recommended that the Board approve YECL's requested deferral account.[137]

UCG submitted that the deferral account for YECL's ROE should be denied[138].

YEC provided three reasons to deny the ROE deferral account[139].

(1) No Yukon precedent.

(2) Shifting of risk to ratepayers without commensurate benefits.

(3) YECL could not provide any precedent for this form of deferral account used by utilities in other jurisdictions.

YECL noted that the BCUC reinstituted the AAM for reasons of regulatory efficiency by avoiding frequent costly and time-consuming ROE proceedings. YECL stated the same applies to its ROE requested deferral account and would be consistent with Board Order 2009-02[140].

In reply, WL urged the Board to reject the YECL request for the deferral account.[141] WL stated its position aligned with that of YEC and added that if the Board approved the

[136] YECL Application, page 8-6
[137] LE Final Argument, page 5.
[138] UCG Final Argument, paragraph 211.
[139] YEC Final Argument, pages 11-12.
[140] YECL Final Argument, paragraphs 73 and 74.
[141] WL Reply Argument, pages 3 and 4.

deferral account it would effectively be abdicating its legislative authority and mandate to determine this matter. Further, WL said that deferral accounts should be symmetrical and share risks. YECL's proposal was one-sided.

UCG replied that if YECL wanted an AAM it should have supplied supporting relevant evidence.[142]

YECL replied that its ROE deferral account is "consistent with the approach taken by this Board in Board Order 2009-02, where it held that Yukon Electrical's ROE for 2009 should be whatever the BCUC benchmark ROE was to be for 2009."[143] YECL then noted that, in its compliance filing, the Board approved an ROE for YECL based on the BCUC benchmark.

8.1.2.1 Views of the Board

In Appendix A to Board Order 2009-02, the Board states:

> Therefore, the Board directs that the BCUC generic cost of capital is the most appropriate as it has been the most recently reviewed, and is generally accepted by the parties. [emphasis added]

The Board finds no reference in Appendix A to Board Order 2009-02 to a deferral for ROE. It referred to the most recently reviewed BCUC generic cost of capital.

The Board has an additional concern with the YECL proposal. The Board considers that the proposed deferral account is asymmetrical in that it shifts risks to customers.

For the above reasons, the Board rejects YECL's request for an ROE deferral account and an AAM.

8.1.3 Common equity ratio

On page 8-6 of the Application, YECL requested to increase its common equity ratio from the current level of 40 percent to 44 percent for each of 2013, 2014, and 2015. YECL cited the increase in the BCUC benchmark common equity ratio of 3.49 percent (to 38.5 percent), of the increase in the Northland Utilities (Yellowknife) Ltd. common equity ratio of 3.93 percent (to 43.5 percent) and the increase in the Northland Utilities (NWT) Ltd. common equity ratio of four percent (to 44 percent).

In response to YUB-YECL-31, YECL stated the following:

> At the outset, it should be noted that Yukon Electrical's request for an increased common equity ratio arises primarily from the recognition in other jurisdictions that similar increases have been approved for other utilities which has Yukon Electrical has been compared or benchmarked against.

And

[142] UCG Reply Argument, paragraph 53.
[143] YECL Reply Argument, paragraph 99.

> Further to the above, it is Yukon Electrical's position its business risks for this Application remain largely consistent with those assessed in 2008 as part of its 2008-2009 GRA.

LE argued that YECL has a history of over-earning on its ROE and disagreed that the risk faced by YECL merit a common equity thickness level beyond 40 percent.[144]

UCG noted that in the BCUC GCOC proceeding, the benchmark common equity decreased by 1.5 percent to 38.5 percent[145].

YEC summarized YECL's position regarding business risks as:[146]

> (1) Higher than those of a typical Canadian distribution utility.
>
> (2) Higher than average within the spectrum of Canadian utilities.
>
> (3) The capital structure for Yukon Electrical should respect the stand-alone principle. [Footnote omitted]

YEC noted that the above issues were determined in Board Order 2009-02 and the positions of YECL on those issues were rejected by the Board[147].

It was later added by YEC that YECL's use of comparisons to utilities outside Yukon ignored existing precedents within Yukon[148].

YECL argued that at the time the Board issued Board Order 2009-02, the BCUC GCOC equity ratio was 35.01 percent and the Board set YECL's equity ratio at 40 percent — 4.99 percent higher. YECL further added that the most recent decisions for equity thickness for Northland Utilities (Yellowknife) Ltd. was 43.5 percent and for Northland Utilities (NWT) Ltd. was 44 percent,[149] recognizing that this Board has historically compared or benchmarked YECL to these jurisdictions.

YECL added that it still supported the evidence of Ms. McShane from its 2008-09 GRA and that the stand-alone principle was supported by the BCUC in its most recent GCOC proceeding[150].

YECL acknowledged that its business risks were less than those of YEC[151]; it submitted that YECL should not be penalized because YEC has not requested to increase its historical capital structure.

UCG replied that the use of the cost-of-capital review from YECL's 2008-09 GRA is now over five years old and that review was implicitly rejected by this Board. UCG submitted

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[144] LE Final Argument, page 5.
[145] Information Responses YEC-YECL-13(a), Attachment 1, page 54 and UCG Final Argument, paragraph194.
[146] YEC Final Argument, pages 7-8.
[147] YEC Final Argument, page 8.
[148] YEC Final Argument, page 8.
[149] YECL Final Argument, paragraphs 65-68.
[150] YECL Final Argument, paragraphs 69-71.
[151] YECL Final Argument, paragraph 72.

that the equity thickness for YECL should be set in accordance with that of Fortis Energy from the BCUC GCOC proceeding, namely at 38.5 percent[152].

YEC replied, as acknowledged by YECL, that YECL's business risks are somewhat less than those of YEC; therefore, it makes no sense for YECL to have an approved equity ratio that is four-percent higher than YEC's. Regarding the previous evidence supplied my Ms. McShane in the YECL 2008-09 GRA, YEC stated "Asking for less based on evidence that was clearly rejected by the Board in a prior proceeding does not make the basis or rationale for the request reasonable at this time"[153].

YECL replied that its "position that respect for the stand-alone principle is a critical factor that allows for a fair and reasonable assessment of its business risk and the requested ROE and equity ratio"[154].

The response to YUB-YECL-33(b) was referred to by YECL[155] to demonstrate that YECL's equity thickness and ROE request is in line with that requested by BC utilities in the second phase of the BCUC GCOC proceeding.

8.1.3.1 Views of the Board

The direction given regarding the stand-alone principle in Appendix A to Board Order 2009-02 speaks for itself. The Board has not been persuaded in this proceeding to alter that position.

In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application.

The Board accepts the position of YEC that if YEC's business risks are higher than those of YECL, then it would not make sense to approve an equity ratio for YECL higher than that approved for YEC.

Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.

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[152] UCG Reply Argument, paragraphs 49 and 52.
[153] YEC Reply Argument, page 7
[154] YECL Reply Argument, paragraph 95.
[155] YECL Reply Argument, paragraph 97.

8.2 Costs of debt

The following table was provided by YECL on page 8-7 of its Application to determine its recommendation for its cost of debt:

Table 13. **YECL Cost of Debt Calculations**

	2013	2014	2015
Long Canada Bond Rate	2.4-3.1%	3.2-3.7%	4.0-4.4%
Credit Spread	1.45-1.65%	1.45-1.65%	1.45-1.65%
Debenture Rate	3.85-4.75%	4.65-5.35%	5.45-6.05%
Recommended Rate	4.30%	5.00%	5.75%
Issue Costs	0.05%	0.05%	0.05%
Recommended All-In Rate	4.35%	5.05%	5.80%

In argument, CW stated that since 2009, ATCO Electric (the parent of YECL) has had a history of over-forecasting interest rates for long-term debt.[156] The forecasting variances were shown when comparing the responses to CW-YECL-11(b) and (c).

UCG noted that in Board Order 2013-01, the Board ordered a formulaic approach of using 120 basis points above long-term Canada bonds. UCG later added that according to the BCUC GCOC report, long-term Government of Canada default free bonds were in the 2.6 to three percent range[157].

UCG recommended a deferral account[158] for cost of debt as it met YECL's criteria for a deferral account.

In WL-YECL-18(c), YECL updated its long-term debt rates to 4.70 percent (2013), 5.15 percent (2014) and 5.8 percent (2015). The actual 2013 cost of debt for YECL was 4.761percent[159]. YECL did not seek to further update its forecast[160]. YECL did not agree with UCG that a deferral account is necessary.

UCG replied that "experience has been that YECL's forecasts tend to be in error in favour of YECL,"[161] and therefore, a deferral account is warranted.

In reply argument, YEC stated:

> …Yukon Energy does not see a sound basis today for a forecast of rising long term debt rates as set out in the Application or YECL's updated forecasts for

[156] CW Final Argument, pages 15-16.
[157] UCG Final Argument, paragraphs 227, 229 and 230.
[158] UCG Final argument, paragraphs 233 and 234.
[159] November 4, 2013 transcript, page 135, line 21 to page 136, line 6.
[160] YECL Final Argument, paragraph 76.
[161] UCG Reply Argument, paragraph 55.

> 2014 or 2015 above about 5%. Although YEC does not support YECL's advocacy of multiple new deferral accounts, if the Board is to approve this shift towards additional deferral accounts then UCG's proposal for similar treatment of debt rates would merit consideration.[162]

YECL explained that the reason interest rates were lower than forecast for the 2010 to 2012 time period was due to the central bank stimulus activities[163]. The external forecast prepared by BMO Capital Markets, TD Economics, RBC Economics and Consensus Forecasts was provided in response to WL-YECL-18 (c).

8.2.1 Views of the Board

As in Board Order 2009-02, the Board accepts that the best information in terms of actual debt costs that become available after the application was filed should be considered. For this particular application, YECL incurred actual debt costs of 4.761 percent. Therefore, for 2013, the Board directs YECL to use 4.7615 as its cost of debt in its compliance filing.

For 2014, in response to WL-YECL-18 (c), YECL provided a 30-year Canadian yield curve from BMO Capital markets, a Canadian 30-year Government Bond Yield from TD Economics, a Canadian 30-year interest rate outlook from RBC Economics and a 10-year government bond yield from Consensus Forecasts. A summary of the forecast is in the table below:

Table 14. **YECL Forecast Interest Rates for 2014 (%) (30 year yield or bond rate)**

Source	High Point	Low Point	Mid-Point
BMO	3.9	3.3	3.6
TD	3.25	3.10	3.18
RBC	3.75	3.40	3.58
Consensus*	3.2	2.2	2.7
Average	3.53	3.0	3.27

Source: * - Consensus forecast was for a 10 year government bond yield at the end of July 2014.

The Board notes that in YECL's Attachment 4 to WL-YECL-18(c), YECL did not include the full page that provides all the forecasters in the consensus forecast. That is, some of the forecasts in the consensus forecast may have been provided by BMO, TD or RBC.

On page 8-7 of the Application, YECL showed how the recommended all-in rate was determined. YECL determined a spread of rates for the Long Canada Bond Rate. Then YECL determined a credit spread and added the credit spread to the Long Canada Bond Rates to determine the Debenture Rate. The mid-point of the debenture rate

[162] YEC Reply Argument, page 8.
[163] Information Responses, CW-YECL-11(c).

became the Recommended Rate. Issue costs of 0.05 percent were added to the recommended rate to provide the recommended all-in rate.

The forecasts by BMO, TD and RBC showed upward trends as you moved from Q1 to Q4 in 2014. The mid-point credit spread as utilized by YECL was 1.55 percent. For 2014, if the Board takes the average of the high points for 2014 as provided by YECL and adds the mid-point for the credit spread, again as provided by YECL, the Board calculates a 2014 cost of debt for YECL of (3.53 + 1.55) = 5.08 percent. This is the rate that the Board directs YECL to use for its cost of debt for 2014 in its compliance filing.

YECL did not provide any evidence to corroborate its Long Canada Bond rate for 2015. YECL did testify that it was not aware of the Bank of Canada signaling any changes in short term interest rates[164] but did note that comments by the Chairman of the Federal Reserve (U.S.) regarding the tapering of the U.S. government stimulus program resulted in increases in long-term paper in the U.S and then into Canada.

In response to UCG-YECL-31(a) Attachment 1, YECL does not forecast any long-term debt to be issued in 2015.

Given that YECL does not currently plan to issue any debt for 2015 and the lack of evidence corroborating its 2015 cost, the Board directs YECL to use the 2014 cost of debt for 2015 in the compliance filing in case there is a change in the timing of debt issuance.

8.3 No cost capital

YECL included the following continuity table for no-cost capital on page 8-8 of the Application:

Table 15. **YECL Forecast No-cost capital**

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Test Period 2013	2014	2015
				($000)				
No Cost Capital	693	702	666	649	631	632	651	670

8.3.1 Views of the Board

Subject to the findings in the section on pension costs, the Board accepts YECL's forecast for no-cost capital as filed.

9 INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On January 1, 2011, YECL, consistent with its parent company, started following IFRS for annual financial statements relating to fiscal years beginning on or after January 1, 2011. YECL stated that this meant it no longer recognized regulatory assets and liabilities in its IFRS Financial statements, but did continue to do so for utility earnings purposes. YECL said that this activity added complexity and time to all of

[164] November 4, 2013 transcript, page 135, lines 13-20.

YECL's accounting functions[165]. Attachment 2 to Section 1 of the Application provided a summary comparison of significant items under IFRS versus regulatory accounting.[166]

YECL confirmed that IFRS was the standard adopted by YECL, its parent company, and affiliate companies Northland Utilities (Yellowknife) Ltd. and Northland Utilities (NWT) Ltd.[167]. The requirement for an unqualified financial statements audit opinions of YECL, AE and CU Inc. supports CU Inc.'s ability to access capital markets at favorable rates,[168] which is a benefit to YECL. YECL determined the annual costs on a go-forward basis to be $43,000[169] in 2012 dollars.

UCG argued that the Board should ensure that YEC and YECL are developing and implementing consistent plans to transition to IFRS and that the Board should carefully consider the potential impacts and costs related to IFRS. In addition, UCG submitted that YECL implemented IFRS early and therefore YECL's parent should absorb 50 percent of IFRS work during the test period due to the premature adoption of these new accounting standards. Finally, UCG asked the utilities to identify financial differences due to the new standards and how rate mitigation mechanisms will be used, and for YECL to provide a report during 2014 on how IFRS requirements will be addressed by YECL[170].

YECL replied that many of the requests by UCG were contained in YECL's Application[171]. Later, YECL added that YECLs forecast annual costs for the test years regarding IFRS would be prudently incurred.

9.1 Views of the Board

Subject to Board determinations regarding labour costs and FTE forecasts, the Board accepts YECL's IFRS submissions.

10 CAPITAL ADDITIONS

YECL submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. YECL's actual and forecast capital expenditures and additions for the period from 2008 to 2015 are shown in the following table.

[165] YECL Application, page 1-13.
[166] YECL Application, Section 1, Attachment 2, pages 1-6
[167] Information Responses, WL-YECL-6 (a & b).
[168] Information Responses, WL-YECL-7(a).
[169] Information Responses, WL-YECL-7(b)
[170] UCG Final Argument, paragraphs 157-163.
[171] Financial differences were contained in Section1, Attachment 2 of the application. Similar information is found regarding third party contributions. YECL further noted that deferral account and regulatory balances are required to be written off under IFRS, but the Board has full authority to order how items are recorded for revenue requirement purposes. YECL Reply Argument pages 20-22.

Table 16. **2008-2015 Capital expenditures and additions ($000)**

	Actual					Test Period		
Description	2008	2009	2010	2011	2012	2013	2014	2015
Capital Expenditures	9,906	6,253	9,388	14,938	14,590	20,282	22,417	20,820
Capital additions to rate base	9,170	7,469	6,848	12,266	17,116	21,962	23,017	20,820

Source: Application, page 9-1.

As can be seen from the table, capital expenditures for 2013, 2014 and 2015, are forecast to increase by 39, 54 and 43 percent respectively, when compared to 2012 actual expenditures. Capital additions to rate base for the test period, are forecast to increase by 28, 34 and 22 percent, for 2013, 2014 and 2015 respectively, when compared to 2012 actual capital additions to rate base.

Generally, with the exception of projects described in the following sections, capital additions are categorized as generation assets, new extensions, distribution improvements, street and sentinel lights, meters, and general property and equipment. Generic descriptions of each category and a listing of projects that make up the dollars shown in Table 4 of the Application and are detailed in pages 9-1 to 9-67 of the Application.

On October 31, 2013, YECL filed its updated forecast. The following table outlines the updated forecast related to capital expenditures and capital additions to rate base for the test period.

Table 17. **YECL updated forecast; capital additions and expenditures**

	Test Period		
Description	2013	2014	2015
Capital Expenditures	19,894	22,660	20,696
Capital additions to rate base	21,574	23,260	20,696

Source: Exhibit B-11, YECL Updates 2013-15 GRA, October 31, 2013, page 4

With respect to street and sentinel light capital additions, YECL submitted that it had partnered with YEC in a joint pilot project study to determine the best suited light-emitting diode (LED) street light technology for Yukon. YECL added the pilot project is currently testing four different LED lights and will be completed by the end of 2013.[172]

Given the pilot work done to date by YECL and YEC that is to be completed at the end of 2013, and the pilot work of other utilities throughout North America, LE submitted that there is no reason for YECL not to start installing LED street and sentinel lights during 2014.[173] Accordingly, LE recommended that the Board direct YECL to begin the

[172] Information Responses, LE-YECL-13.
[173] The Board in decisions 2009-02 and 2009-08 stated that energy efficiency and conservation are a critical issue to all Yukon ratepayers; LE Final Argument, page 6

installation and replacement of street and sentinel lights with appropriate LED models by mid-2014.[174]

10.1 Views of the Board

The Board notes that YECL's submission that it is "prudent to have thorough testing completed to ensure that LED lights perform to an appropriate standard in light intensity and lighting patterns for the Yukon."[175] The Board finds it reasonable that YECL should have a thorough understanding of the issues at hand prior to initiating a street and sentinel light installation and replacement program. The Board therefore rejects LE's recommendation.

10.2 Deferred study costs

In the Application, YECL submitted that, consistent with the treatment of deferred overhauls approved in the 1996-97 and 2008-09 GRA proceedings, YECL continues to defer the costs associated with major cyclical diesel plant overhauls and rebuilds. "These costs are written off over a five-year period commencing from the time of the overhaul."[176] Mid-year deferred charges and credit amounts, which YECL included in rate base, are as follows:

Table 18. **2008-2015 Deferred charges and credits ($000)**

	Actual					Test Period		
	2008	2009	2010	2011	2012	2013	2014	2015
Mid-year balance	464	270	269	(457)	(515)	(268)	118	175

Source: Application, page 8-10.

UCG pointed out that the used or required to be used language in the *Public Utilities Act* "prohibits YECL from earning a return on costs that were never included within a capital project."[177] Accordingly, UCG submitted that all deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset. UCG added that amortization of prudently incurred project development costs over a period of years should be done without placing the balance in the rate base, thereby allowing a return of, but not on, the investment. In summary UCG submitted that "all deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."[178]

10.2.1 Watson Lake bi-fuel project study costs

A description of this project is provided in Section 10.8.2 of this decision. YECL submitted that it will incur $222,000 for study costs incurred in 2012 and 2013, which include consulting costs for feasibility, surveying, engineering and acquisition of required permits and licenses. YECL proposed to amortize these study costs over 10

[174] LE Final Argument, page 6.
[175] Information Responses, LE-YECL-13.
[176] YECL Application, page 8-11, lines 12-13.
[177] UCG Final Argument, paragraph 249.
[178] UCG Final Argument, paragraph 253.

years. In its updates filing, YECL proposed that the deferred charges associated with this project be amortized beginning in 2014, rather than 2013, because of a delay in project completion.

UCG asserted that YECL had only provided a high-level summary breakdown of project study costs without providing detail such as "who undertook the various study components and what are their qualifications, how the service contracts were awarded, and the actual results of the study."[179] Accordingly, UCG submitted that YECL had not justified the recovery of these costs. UCG submitted that these study costs should remain in work in progress (WIP) until the project has been commissioned and all costs have undergone a comprehensive prudency review.

YECL submitted that the project has received approval through the Yukon Environmental and Socio-economic Assessment Board (YESAB) process and will bring benefits to ratepayers. YECL further submitted that the study costs were reasonably incurred and should be approved as filed.[180]

10.2.1.1 Views of the Board

The Board, as acknowledged in Board Order 2013-01, Appendix A: Reasons for Decision, understands that utilities need to explore alternatives to diesel generation, despite concerns related to costs for such studies. Furthermore, with respect to deferred costs for projects between $100,000 and $1 million, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in WIP until such time that the project is set aside or the utility comes before the Board for a prudence review:

> Moreover, for project expenditures incurred in the test years and beyond, the Board directs that these expenditures be held in WIP until such time the costs are brought before the Board for a prudence review and have been approved.

Despite the Board having rejected YECL's proposed Watson Lake bi-fuel project in Section 10.8.2 of this decision, the Board finds that this project has potential to be viable in the future. Accordingly, the Board directs that all Watson Lake bi-fuel project study costs to date be held in WIP until such time as the project may be completed. The Board further directs YECL to reflect this finding in its compliance filing.

10.2.2 Kluane wind study

YECL submitted that it will incur consulting costs totaling $20,000 to study the feasibility of using wind to generate power in the Burwash and Destruction Bay area. YECL proposed to collect this amount from customers over the test period.[181]

UCG indicated that YECL had failed to provide the necessary information to allow for a proper prudence review of the costs associated with this project. UCG therefore

[179] UCG Final Argument, paragraph 260.
[180] YECL Reply Argument, paragraph 123.
[181] YECL Application, page 8-11.

submitted that these costs should not be recovered until a more thorough review can be conducted based on more extensive disclosure and a capital project materializes.[182]

YECL submitted that this study was important to YECL's consideration of energy alternatives that interveners have been promoting for some time. YECL pointed out that YEC incurred and had similar-type deferred charges approved in Board Order 2013-01.

10.2.2.1 Views of the Board

The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study.

10.3 Project cost overruns

UCG expressed concerns with the significant expenditures over approved budget amounts for which many of the capital projects that had been previously approved. UCG submitted that YECL should not be allowed to add cost overruns to rate base unless they can provide evidence as to the reasons for the cost overruns given the approved scope of the projects.[183] UCG noted the following project overruns:

(a) Hamilton Boulevard extension (streetlighting) project — UCG noted the $476,000 total cost of the project compared to the approved $200,000 project expenditure;[184]
(b) Fish Lake unit #1 generator end-of-life rebuild project — UCG noted the $463,000 total cost of the project compared to the approved $125,000 project expenditure;[185]
(c) Connecting Pelly Crossing into the grid project — UCG noted the $435,000 total cost of the project compared to the approved $140,000 project expenditure;[186]
(d) Oracle HRxcellence human resource (HR) management project — UCG noted that the Board did not approve any expenditures for this project in 2008 and 2009; however, YECL spent $358,000 on this project in the period from 2008 to 2010;[187]
(e) Ketza Court life front transformers replacement project — UCG noted the $346,000 total cost of the project compared to the approved $175,000 project expenditure;[188]
(f) 5L628 Squanga Road rebuild project — UCG noted the $290,000 total cost of the project compared to the approved $140,000 project expenditure.[189]

[182] UCG Final Argument, paragraph 264.
[183] UCG Final Argument, paragraph 245.
[184] UCG Final Argument, paragraph 325.
[185] UCG Final Argument, paragraph 330.
[186] UCG Final Argument, paragraphs 335 to 337.
[187] UCG Final Argument, paragraph 338.
[188] UCG Final Argument, paragraph 341.
[189] UCG Final Argument, paragraph 347.

YECL submitted that actual project costs vary from forecast for many reasons, many of which are beyond the control of YECL. Detailed explanations for why the actual costs for each of the projects forecast in the 2008-09 test period, including why the projects identified by UCG, varied from the original forecast were provided by YECL in response to WL-YECL-21(k). YECL submitted that UCG had not provided any evidence that the identified projects were not used and useful nor that the actual project costs were not prudently incurred, and recommended that the Board reject UCG's submission that the projects should not be included in rate base.

10.3.1 Views of the Board

The Board acknowledges YECL's submission that actual costs may vary from forecast for a variety of reasons. Respecting the above-noted projects the Board notes YECL's submission regarding the overruns and the following variance explanation:[190]

(a) Hamilton Boulevard extension (streetlighting) project – a Yukon government contributed project, the scope of the project was increased at the customer's request;
(b) Fish Lake unit #1 generator end-of-life rebuild project - the original estimate arose from a third party recommendation that the generator be cleaned and stator core work. Upon removal of the unit from service, an in-depth inspection found that a complete rebuild of the unit was necessary;
(c) Connecting Pelly Crossing into the grid project- the scope of the project was adjusted after filing the GRA;
(d) Oracle HRxcellence human resource (HR) management project – unplanned change to company HR management system;
(e) Ketza Court life front transformers replacement project – the original scope of the project changed to complete all five transformers in the complex and associated underground infrastructure;
(f) 5L628 Squanga Road rebuild project – due to the location of existing water lines being different than the original plan, a new route was required. Conflicts with property lines, existing vegetation, water lines and the existing power line, the new power line was built with underground infrastructure rather than overhead as originally designed.

The Board notes UCG's submission that "any capital expenditure that more than doubles between approved budget and actual expenditure should be subject to review"[191] before it is added to rate base. Further noted is UCG's statement that if a project's scope has changed, YECL should be held at risk for any expenditures until the Board has had the opportunity to review the project.[192]

With respect to UCG's submission, the Board has provided interveners the opportunity to test the reasonableness and prudency of the capital additions before they are approved by the Board for inclusion in YECL's rate base. Further, the Board understands that project scope can change due to unforeseen circumstances, many of

[190] Information Responses, WL-YECL-21(k), Attachment 1.
[191] UCG Final Argument, paragraph 328.
[192] UCG Final Argument, paragraph 333.

which may be beyond the control of a utility. Moreover, it can become economical to change all instead of part of an existing infrastructure that may need replaced.

There is no evidence to suggest that the above-noted projects are not used and useful. Moreover, there is no evidence that suggests that the actual project costs were not prudently incurred. Accordingly, the Board rejects UCG's submission that the above-noted projects should not be included in rate base.

However, YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100 percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL in future applications is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.

10.4 Limiting project expenditures to the average net expenditures of last five years

YECL provided the following information regarding miscellaneous overhead (O/H) services, miscellaneous underground (U/G) services and right-of-way (ROW) widening and transportation equipment for the period 2008 to 2015.

Table 19. **Continuity of capital additions 2008 – 2015 ($000)**

	2008	2009	2010	2011	2012	2013	2014	2015
Miscellaneous O/H services various subdivisions	1,304	969	1,022	1,274	992	3,625	2,900	4,300
Miscellaneous New U/G services	95	36	86	216	144	600	1,000	1,000
Right-of-way widening	268	240	304	331	377	374	389	405
Transportation Equipment	139	100	358	257	421	424	995	400

Source: YUB-YECL-61, Attachment 1, pages 2, 4 and 6 of 6.

With respect to miscellaneous new O/H and U/G services expenditures, UCG noted that for the test period, expenditures were significantly greater than the expenditures YECL had incurred for the previous five years.[193] UCG further acknowledged YECL's submission that miscellaneous O/H services were difficult to forecast as the budget item

[193] Miscellaneous new O/H services - $5,561,000 (2008-2012) compared to $10,825,000 for the test period, UCG Final Argument, paragraph 270; miscellaneous new U/G services - $577,000 (2008-2012) compared to $2,600,000 for the test period, UCG Final Argument, paragraph 274.

was totally dependent on customers and contractors walking into the office requesting the service. Bearing this in mind, UCG submitted that the miscellaneous O/H and U/G services expenditure forecasts should be based on averages of the last five year expenditures:

> …for additions to rate base related to Miscellaneous O/H Services for each of the test years should be limited to the average of the net expenditures over the last 5 years of actual expenditures (i.e., net of customer contributions).[194]
>
> …
>
> …for additions to rate base related to Miscellaneous U/G Services for each of the test years should be limited to the average of the net expenditures over the last 5 years of actual expenditures (i.e., net of customer contributions).[195]

YECL pointed out that for the five-year period prior to the test period, where the actual projects completed are known, only the new extension projects less than $25,000 are reported as miscellaneous projects — i.e. "projects with values greater than $25,000 are separately identified."[196] For the test years, where there is less certainty regarding new extension projects that will be completed, a greater amount is forecast in the miscellaneous categories. YECL submitted that its response to Undertaking #6,[197] was a better representation of the actual and forecast amounts respecting miscellaneous O/H and U/G new extension projects. It states:

Table 20. **New extension capital expenditure projects 2008 – 2015 ($000)**

	2011	2012	2013	2014	2015
Miscellaneous O/H Services – Various *	3,148	3,083	3,625	2,900	4,300
New Underground Line Extensions **	960	1,153	600	1,000	1,000

Source: Response to Undertaking #6, Attachment 1.

* Includes all small projects included in Miscellaneous O/H Services – Various in Section 9 of the Application as well as those projects in 2011 and 2012 that were originally forecast as part of this category.
** Includes all small projects included in New Underground Line Extensions in Section 9 of the Application as well as those projects in 2011 and 2012 that were originally forecast as part of this category.

YECL submitted that the analysis shows that YECL's miscellaneous O/H and U/G new extension forecasts are reasonable as compared to prior period actual amounts. YECL also submitted that, using the five-year average as suggested by UCG does not account for other factors YECL used to forecast new extensions, which include YECL's knowledge respecting areas of development within its service area.[198]

[194] UCG Final Argument, paragraph 273.
[195] UCG Final Argument, paragraph 276.
[196] YECL Reply Argument, paragraph 124.
[197] 2013-11-13 YECL Undertakings.
[198] YECL Reply Argument, paragraphs 124 and 125

With respect to transportation equipment expenditures, UCG submitted that 2014 and 2015 expenditures warrant a business case. UCG stated that there is no difference between a capital program with annual expenditures and a capital project with expenditures spread over multiple years. UCG recommended that the transportation equipment budget amounts for each of the test years should be limited to the average of actual expenditures for the period from 2008 to 2012. Furthermore, any "components of the $2.855 million (2010-2015) transportation equipment program that have not been justified as part of a business case should not be added to YECL's rate base."[199]

YECL submitted that in response to YUB-YECL-72, it had provided an extensive amount of detailed evidence regarding its forecast transportation equipment additions. The evidence included business cases for all additions for the test period and the details of YECL's replacement policy. YECL explained that the existing pieces of transportation equipment are of varying vintages and mechanical condition, thus giving rise to the nonlinear replacement timelines and costs.[200] YECL asserted that the forecast for the transportation equipment is based on existing equipment which will be reaching the end of life. Furthermore, accepting UCG's recommendation ignores the evidence, which UCG has not challenged.[201]

Regarding the right-of-way widening expenditure, UCG noted that the Board approved right-of-way widening expenditures of $110,000 in 2008; however, there was no budget included in the 2009 GRA. UCG acknowledged YECL's variance explanation that in 2008,

> …the scope increased on the basis of line patrols as Yukon Electrical focused on completing brushing of our mountain top distribution lines in Whitehorse and Stewart Crossing. In 2009, the right of way brushing program continued.[202]

UCG noted that the Board, in Order 2009-2, directed YECL to provide an annual update on its capital plans and expenditures. UCG further noted that there was no evidence indicating that YECL had notified the Board of the changes to brushing in 2008 and 2009 Accordingly, UCG recommended that the Board direct YECL to remove the "cost consequences of the right-of-way widening projects that they undertook in excess of approved budgets [for the period from 2008 to 2012]."[203]

Additionally, UCG submitted that the 2013 to 2015, $1,168,000 total right-of-way widening expenditures warrant a business case to justify the expenditures and it was inappropriate for YECL not to provide a business case. Accordingly, UCG recommended that components of the $1.2-million right-of-way widening program that have not been justified as part of a business case should not be added to YECL's rate base.

YECL indicated that a business case for the right-of-way widening program was not filed as it is made of many smaller projects that are well below the $500,000 business case

[199] UCG Final Argument, paragraph 301.
[200] November 4, 2013 transcript, page 120, lines 2-12.
[201] YECL Reply Argument, paragraph 126.
[202] Information Responses,WL-YECL-21(k), Attachment 1, page 2 of 3.
[203] UCG Final Argument, paragraph 319.

threshold. YECL further noted that a large amount of evidence has been included on the record regarding the need for the program and the prudence of the amounts spent on right-of-way widening from 2008 to 2012. Accordingly, YECL submitted that UCG's recommendation to limit the right-of-way widening forecasts has no evidentiary support and should be rejected.

10.4.1 Views of the Board

With regard to miscellaneous O/H and U/G expenditures, the Board notes YECL 's response to Undertaking #6 and finds the miscellaneous O/H and U/G new extension forecasts to be reasonable when compared to prior period actual amounts.

Respecting the forecast transportation equipment expenditures, the Board finds it reasonable because YECL's existing transportation equipment is of varying vintages and commensurate mechanical condition, which in the normal course of events would give rise to nonlinear replacement timelines. The Board finds that year-to-year variations are reasonable and denies the UCG recommendation to limit the transportation equipment budget amounts for each of the test years to the average of actual expenditures for the period from 2008 to 2012.

The Board notes YECL's submission that it is conducting the right-of-way widening program to allow for safer power line access for maintenance and emergencies, to reduce the potential for wild fires resulting from contact with power lines and to improve customer reliability and safety by having less tree contacts with the distribution system.[204] Furthermore, the Board observes that many areas identified for brushing, actual and forecast, by YECL are in a diverse service territory, which adds complexities to YECL's brushing program. The Board finds YECL's forecast expenditures reasonable and rejects the UCG submission to deny costs of YECL's right-of-way projects undertaken in the period from 2008 to 2012, as no evidentiary basis was found to support the submission.

With respect to ongoing maintenance programs such as YECL's right-of-way widening program, parties registered in a proceeding have the opportunity to test the evidence or cross-examine the utility in respect of actual and forecast expenditures. The Board finds it unnecessary to direct YECL to justify ongoing expenditures through a business case as this would merely add expenses with no added efficiencies. As a result, the Board rejects the UCG recommendation that components of the $1.2-million right-of-way widening program that have not been justified as part of a business case should not be added to YECL's rate base.

10.5 CIS billing system conversion

The North of 60 Companies[205] were advised in 2006 that ATCO I-Tek Business Services intended on retiring the customer information system (CIS). YECL pointed out that while CIS met YECL's business needs at the time, the loss of the Alberta-based utilities meant a loss of economies of scale and exposed the North of 60 Companies and the

[204] Information Responses, CW-YECL-12(d)(i).
[205] The North of 60 Companies (The Yukon Electrical Company Limited, Northland Utilities (Yellowknife) Ltd. and Northland Utilities (NWT) Ltd.).

non-affiliated YEC to the full cost of running and supporting the CIS. With the realization that the customer care and billing system was over 30 years old and based on a technology that was no longer economically supportable, the North of 60 Companies undertook and completed a detailed search and evaluation of various billing solutions. Based on investigative and analytical work that was completed, it was recommended to proceed with the implementation of ATCO-CIS in 2008.[206] The customer care and billing system conversion project was completed in 2008.

UCG noted that YECL's response to UCG-YECL-48(c) provided details of the costs associated with the new system but nothing regarding the cost savings. UCG noted YECL's testimony that the cost savings identified as part of the business case in the 2008-09 GRA were achieved. UCG submitted that, until details of the actual cost and cost savings can be identified and verified, the project could not be comprehensively reviewed for prudency and should not be added to rate base.[207]

YECL pointed out that the new billing system was approved because the previous billing system was rapidly becoming obsolete and the past economies of scale for the operations of that system had been lost, which would result in future cost increases. Furthermore, at the time, YECL indicated that cost increases would be less for the new system than would occur if the legacy system remained in place. The need for the project was not approved solely based on cost savings. Moreover, YECL asserted that the costs it has been incurring respecting the new billing system, on a capital as well as an operational and maintenance basis, are exactly as forecast. Furthermore, the $27,000 variance, $1,515,000 (actual cost) vs. $1,488,000 (approved cost), is reasonable and there should be no associated disallowance of these prudently incurred costs. YECL submitted that UCG's suggestion that the project should not be added to rate base should be rejected.[208]

10.5.1 Views of the Board

The Board notes YECL's submission that the previous customer information billing was obsolete and no longer economically supportable. Furthermore, the Board, in Order 2009-02 accepted that "a new billing system is required by YECL and, absent other evidence, the evidence on the record supports YECL's choice for its new billing system."[209]

With respect to the system that is in place, the Board took note of YECL's submission that the costs that it has been incurring, on a capital basis, as well as an operation maintenance basis, are as forecast. The Board finds that a $27,000 variance (1.8 percent) is reasonable. Accordingly, the Board rejects UCG's recommendation that the project should not be added to rate base.

[206] Information Responses, UCG-YECL-48 (C), Attachment 1, North of 60 Billing System Replacement Project Business Case.
[207] UCG Final Argument, paragraph 324.
[208] YECL Reply Argument, paragraphs 134 to 136.
[209] Board Order 2009-02, Reasons for Decision – Appendix A, page 40 of 49.

10.6 Other projects

For each of the capital expenditures listed on pages 9-5 to 9-67 of the Application, YECL was requested to provide a continuity table for the period from 2008 to 2015. YECL was further asked to:

> …retain the following headings: Generation Plants, Distribution New Extensions (gross and net of customer contributions), Distribution Improvements, Street and Sentinel lighting, Transformers & Regulators, Meters, General Property & Equipment, CIS Billing System Conversion. Moreover, please ensure that projects that are ongoing from year to year, such as replacement of transportation equipment, replacement of meters and new installations, new underground line extensions, and pole replacement are aligned as one project over the years. [210]

In its response, for the period from 2008 to 2015, YECL provided a continuity table[211] of capital expenditures and a breakdown of actual as well as forecast capital projects with a total project cost greater than $100,000. Furthermore, YECL provided the following "table that presents the information that Yukon Electrical has provided to allow for the testing of the reasonability of its capital forecast."

Table 21. **YECL capital expenditure summary table**

	2008-2015		2013-2015	
Type	$000	%	$000	%
Business Case/Extended Write-ups	40,810	34.41	34,236	53.90
Project Description Write-up	58,033	48.93	25,251	39.75
Listed Projects	15,466	13.04	3,194	5.03
Other Small Projects	4,289	3.62	839	1.32
Total	118,598	100.00	63,520	100.00
Total of Projects detailed in YUB-YECL-61 Attachment 2	104,178	87.84%	61,229	96.39%

Source: YUB-YECL-61, Page 2 of 2.

YECL explained that Other Small Projects for the period from 2008 to 2014, totaling $4,289,000, are comprised of approximately 800 projects, each under $25,000, which equates to an average project cost of approximately $4,361 per project. Accordingly, YECL submitted that it had not listed these projects due to their "immaterial nature on an individual and consolidated basis."[212].

UCG noted that YECL, in 2008 and 2009, significantly underspent approved amounts with regard to the Other Projects category of expenditures:

> …YECL indicates that its 2008 GRA identified $677,500 in "Other Projects" but only $56,000 was spent under "other" because "Other projects were forecasted based on historical capital costs and does not relate to one specific project". [213]

[210] Information Responses, YUB-YECL-61, Request.
[211] Information Responses, YUB-YECL-61, page 2 of 2
[212] Information Responses, YUB-YECL-61, page 2 of 2.
[213] UCG Final Argument, paragraph 350.

> … YECL indicates that its 2009 GRA identified $590,000 in "Other Projects" but only $69,000 was spent under "other" because "Other projects were forecasted based on historical capital costs and does not relate to one specific project". [214]

UCG further noted that YECL's witnesses were unable to clearly explain if or how the money that had been included in rate base was actually spent.[215] Given the lack of evidence, UCG submitted the unspent budgeted amounts related to Other Projects should be removed from rate base.

YECL replied that UCG's submission regarding Other Projects should be rejected. It is only the actual amounts YECL spends on projects that get added to rate base. Further, as YECL testified, other project forecast amounts are subsequently able to be broken down into greater detail when actual amounts are reported.

10.6.1 Views of the Board

The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast."[216] Bearing this in mind, in order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL in future GRAs to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.

10.7 Projects that are related but not included in a business case

10.7.1 Fish Lake unit #1 – generator end-of-life rebuild

UCG noted that $4.6 million in capital projects associated with Fish Lake unit #1 have either been completed or were forecast to be completed following the March 2010 catastrophic failure of the Fish Lake unit #1 plant. These are:

(a) Fish Lake unit #1 Spillway - $238,000 (2010)
(b) Fish Lake unit #1 Replacement Wheel - $125,000 (2010)
(c) Fish Lake unit #1 Tailrace Reconstruction - $173,000 (2011)
(d) Fish Lake unit #1 Turbine and Building Replacement - $3,908,000 (2013)
(e) Fish Lake unit #1 Spillway Diversion Structure - $120,000 (2014)

UCG pointed out that, while YECL had provided a business case for the Turbine and Building Replacement project, nothing has been provided to justify the other four projects that appear to be related to getting unit #1 operational again. In UCG's view, all five of the above projects should have been included in a business case. UCG submitted that YECL should be directed "to ensure that business cases are written for complete capital programs even though individual annual projects related to the same

[214] UCG Final Argument, paragraph 351.
[215] UCG Final Argument, paragraph 352.
[216] YECL reply argument, paragraph 138.

facility are budgeted."[217] UCG further submitted that the four related components identified above that have not been included and justified as part of a business case should not be added to YECL's rate base.

With respect to the Fish Lake expenditures noted above, YECL submitted that:

> …while some capital costs were not the subject of detailed business cases as they were not in excess of $500,000, in YEC-YECL-17(g), Yukon Electrical provided a life cycle cost analysis of the total expenditures over the future expected life of the facility…This life cycle analysis included all actual and forecast costs from 2008 through to 2052 and resulted in a levelized cost of energy ("LCOE") of 12¢/kWh.[218]

YECL pointed that an LCOE of 12¢/kWh compares favorably with other small hydro projects and demonstrates the economic viability of the Fish Lake capital projects included in the Application. In consideration thereof, YECL submitted that the evidence on the record demonstrates that all components of the Fish Lake unit #1 capital program are reasonable and appropriate.

10.7.1.1 Views of the Board

The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudency. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than $500,000.

10.7.2 Whitehorse service storage complex projects

Responding to YUB-YECL-61, YECL submitted a breakdown of actual and forecast capital projects with forecast cost greater than $100,000 for 2008 to 2015. UCG took note of the following three projects totaling $550,000, which were planned for the Whitehorse service complex during the test years:

(a) Whitehorse service complex pole storage - $150,000 (2013);
(b) Whitehorse service complex parking lot extension and improvements - $100,000 (2013); and
(c) Whitehorse service complex yard extension - $300,000 (2015).

UCG affirmed that despite the fact that the projects are related to the same facility, "YECL did not submit a business case for this three part project…there is no difference between a capital program with annual expenditures and a capital project with expenditures spread over multiple years."[219] UCG submitted that the above-noted expenditures have not been justified as part of a business case and should not be added to YECL's rate base.

[217] UCG Final Argument, paragraph 280.
[218] YECL Reply Argument, paragraph 130.
[219] UCG Final Argument, paragraph 345.

YECL submitted that the various Whitehorse storage complex projects, despite being related to the same facility, are based on different needs and drivers. Furthermore, the decision to carry out each project was made independent of the other projects. YECL therefore submitted that grouping the projects together for the purpose of making a decision whether or not to proceed with them would be inappropriate. UCG has not presented contrary evidence as to whether the expenditures are prudent and the results used and useful, and accordingly, the UCG recommendation that these amounts should not be added to rate base should be rejected.

10.7.2.1 Views of the Board

The Board acknowledges YECL's submission that the three projects related to the Whitehorse storage complex were based on different needs and drivers. Moreover, the decision to carry out each project was made independent of the other projects. The Board therefore rejects the UCG recommendation and approves the Whitehorse service storage complex project expenditures as reasonable and prudent.

10.7.3 Meter replacement program

YECL submitted that capital meter additions include new meters that are required to replace obsolete or end-of-life meters as identified by Measurement Canada. For 2010 and forward, this also includes the installation of new meters required to accommodate load growth associated with customer requests for service.[220] YECL submitted the following actual and forecast meter expenditures for the period 2008 to 2015.

Table 22. **Actual and forecast meter expenditures (2008-2015)**

Description	2008	2009	2010	2011	2012	2013	2014	2015
Labour	4,000		100,000	61,000	78,000	150,000	13,000	13,000
Contract services	1,000			11,000	1,000	6,000		
Materials	24,000		347,000	115,000	181,000	414,000	35,000	35,000
Other	2,000		13,000	12,000	23,000	30,000	2,000	2,000
Totals	31,000		460,000	199,000	283,000	600,000	50,000	50,000

Source: YUB-YECL-61, Attachment 2, Page 1 of 8.

Noting the total expenditures for the period from 2010 to 2015, UCG submitted that YECL is requesting that the Board allow a $1.6-million capital program to be added to rate base without the benefit of a business case to justify it. UCG further submitted that 2010 and 2013 expenditures warrant a business case to justify the expenditures. Moreover, it is inappropriate for YECL to not provide a business case by looking at annual expenditures only. Accordingly, UCG submitted that component annual expenditures of the total $1.6 million for 2010 to 2015 that has not been justified as part of a business case should not be added to YECL's rate base.

YECL pointed out that the $1.6 million meter expenditures, additions and replacements from 2008 to 2015, relate to thousands of individual meters over that period of time. The

[220] Prior to 2010, these meters were grouped with new extensions.

quantum of dollars varies from year to year depending on the number of meters required to be replaced. YECL reiterated that expenditures relate to

> … meters are required to be replaced if they fail, if they are obsolete or at end of life as identified by Measurement Canada, or to accommodate load growth associated with customer requests for new service. [221]

Moreover, meter replacements are not discretionary and these expenditures are required for Yukon Electrical to meet its obligation to provide metered service connections.

YECL submitted that its business case threshold of $500,000 is reasonable and strikes an appropriate balance between regulatory efficiency and adequate detail with which to test its forecast. Moreover, YECL submitted that its approach of having different business cases for different components of large capital programs is appropriate when there are separate projects being undertaken at different locations, on different timelines and being completed independently.

10.7.3.1 Views of the Board

The Board notes that meter replacement is not at the discretion of YECL. Per YECL's submission:

> … meters are required to be replaced if they fail, if they are obsolete or at end of life as identified by Measurement Canada, or to accommodate load growth associated with customer requests for new service. [222]

The Board approves the expenditures for actual meter capital additions as prudent. The Board rejects UCG's submission for a business case for the meters in question.

10.8 Major capital projects

In its Application, YECL provided 30 business cases in support of major capital projects $500,000 or greater, and project descriptions for all projects over $100,000. Major capital projects with which the interveners took issue and the underlying business cases are discussed in the following sections.

10.8.1 Automated meter reading – Whitehorse and area (Business Case #27)

YECL proposed this project to convert conventional electronic and mechanical meters to automated meter reading (AMR) technology. The project consists of installing two-way automatic communication system (TWACS) substation equipment at Whitehorse Substation S150 and McIntyre Substation S170. Furthermore, the project would seek to convert all meters in the Whitehorse area, Marsh Lake, Carcross, Tagish and Teslin communities to AMR technology, which is approximately 80 percent of all YECL meters.

[221] YECL Reply Argument, paragraph 131.
[222] YECL Reply Argument, paragraph 131.

In response to Board Order 2009-02 directions, YECL submitted that it undertook "further analysis in respect of the economic benefits of AMR and has presented its Business Case 27 in support of proceeding with this project in the Test Period."[223] YECL submitted that the benefits of conversion would be improved customer service, improved safety performance for employees and customers, reduced vehicle emissions, and long-term cost savings when compared to conventional meter reading. The AMR project cost-benefit analysis shows that "customers will benefit from the implementation of AMR with cost savings in 9 years and cumulative savings of $2.2 million over 25 years."[224] YECL also noted that Measurement Canada had enacted regulations that take effect January 1, 2014, which will increase sample and testing work required on existing mechanical meters, and decrease life extensions of mechanical meters from six to four years. In comparison, AMR meters require testing after 10 years.[225]

YECL submitted the TWACS technology that it is proposing to install does not have Measurement Canada approved TOU revenue metering capability. Explaining its reasoning, YECL explained that it did not intend on applying for TOU rates as there would be little benefit.

> The core purpose of TOU rates is to encourage consumers to shift electrical demand, rather than to reduce overall consumption. In the Yukon, and the AMR implementation area, the patterns of peak consumption closely align with the patterns of residential customer electrical use. Meaning, the peaks are associated with the residential customers' usage. These times of day are before and after work/school during the week. The peak times occur on the coldest days of the year, usually in December or January, when water flows are low. It can be assumed that, due to the load profile of residential customers influence on the peak, implementation of TOU rates would only shift load to a later hour rather than having an overall consumption reduction effect. Therefore, the consumption and associated peaks would still occur, just at a later hour, as residential heating and cooking would still be required regardless of price signals. [226]

YECL added that the TOU ability of the proposed AMR meters would be utilized to conduct load studies on the system. Furthermore, YECL pointed out that if it were to select "a different vendor than TWACS technology, we would lose out on our significant advantage that has been gained by adopting ATCO Electric's ("AE") AMR experience."[227] YECL added that the AMR technology that it is proposing to install has been successfully implemented in the City of Yellowknife.

Considering that the cross-over of savings between AMR meters and the status quo is at least eight years away, UCG submitted that the economic benefits are at risk. Expressing its concern with the lack of detailed evidence related to the computer systems, software and training need to effectively operate an AMR-based system, UCG stated that YECL had understated the overall cost of this project. UCG noted the two-percent escalation rate that was used in the AMR project analysis as compared to key

[223] YECL Final Argument, paragraph 99.
[224] YECL Final Argument, paragraph 100.
[225] YECL Final Argument, paragraph 100.
[226] Information Responses, YUB-YECL-48(n).
[227] Information Responses, YUB-YECL-48(e).

assumptions in YECL's GRA that include a labour inflation rate of 3.5 percent for the test period and other inflation rate of 1.9, 2.0 and 2.1 percent used in 2013, 2014 and 2015 respectively. UCG submitted that YECL has not justified the $3.9 million AMR project to convert conventional electronic and mechanical meters to AMR technology.[228]

YCS submitted that it did not support the cost of the AMR meters being added to YECL's rate base because the meter technology as proposed could not accommodate efficiency and conservation programs designed to manage loads in order to reduce fossil fuel consumption. YCS asserted that it did not want ratepayers paying for obsolete meters when necessary efficiency and conservation measures are in place to manage energy resources. YCS submitted that YECL has not shown that the investment in AMR meters will benefit Yukon ratepayers and the cost should not be included in rate base. Moreover, YCS submitted that it wanted to ensure that any investment in new meters would facilitate and complement demand-side and load-management programs.[229]

YECL replied that YCS ignored the other benefits to the project including long-term cost savings over the life of the project, more accurate meter reads based on the tiered rate structure to provide accurate price signals to customers, and improved employee and customer safety because of decreased vehicle incidents and personal injury incidents. YECL further submitted that the project was based on a proven technology that can be integrated with the billing system in a cost-effective manner to provide tangible benefits to ratepayers. Moreover, if time-of-use rates were implemented in the future, "the [two way automatic communication system] TWACS AMR meters Yukon Electrical is proposing to install could be absorbed into ATCO Electric's existing AMR system and Yukon Electrical would receive credit for the meters."[230] Respecting YCS demand-side and load-management-related concerns, YECL reiterated that the TWACS AMR meters support load control transponders, which could provide control over customer equipment beyond the meter.

CW indicated that while it supports the implementation of technology that can improve the efficiency of utility operations, the implementation must be based on a complete and comprehensive business case. CW submitted that YECL's business case "filed in support of AMR is not complete and does not accurately reflect the costs of the options."[231] From CW's perspective, the AMR business case does not support assertions that YECL had made regarding depreciation rates and replacement of meters. CW asserted that "the business case is not complete, as it does not include any assumption about the replacement of AMR meters."[232] Furthermore, with respect to TOU rates, CW expressed its concern that until there was conclusive evidence either way regarding the imposition of TOU billing, proceeding with AMR at this time may result in additional risk to customers. Accordingly, until YECL provides a business case which includes a reasonable replacement assumption and a more robust assessment respecting the implementation of TOU billing, the AMR project should be denied. CW

[228] UCG Final Argument, paragraphs 287 to 296.
[229] YCS Final Argument, pages 5 and 6.
[230] YECL Reply Argument, paragraph 110.
[231] CW Final Argument, paragraph 35.
[232] CW Final Argument, paragraph 41.

also requested that the Board direct YECL to provide a business case that provides an analysis of TOU rates in Yukon as part of its next Phase II application.[233]

YECL disagreed with CW, stating that its business case was comprehensive, thorough and includes multiple considerations and inputs that were fully tested prior to finalizing the business case. Furthermore, the business case was based on the model of the Northland Utilities (Yellowknife) Ltd.'s AMR project for the City of Yellowknife to ensure that YECL's underlying business case assumptions were reasonable. YECL submitted that meter replacement does not impact the validity of the AMR analysis, as the intent of the business case was to compare the relative costs of the two options. Moreover, Measurement Canada's new regulations and the large number of mechanical meters in service, the new replacement meters coupled with YECL forecast of mandatory meter changes, drives the 1,850 residential and commercial meters that are required to be replaced. Respecting TOU rates, YECL submitted that it did not invest the significant time, effort and dollars to study TOU rates as there was no benefit to ratepayers and no directive to move to TOU rates:

> …preliminary estimates to implement a new technology fully capable of time of use rates and integrate it with the billing system would be significantly more expensive than the proposed AMR project, mitigating any cost benefits of time of use rates to ratepayers.[234]

YECL submitted that, as AMR has clear benefits now for ratepayers and expandability for load management, the proposed project should be approved as filed.

10.8.1.1 Views of the Board

The Board has concerns with the business case because the cross-over of the benefits is still nine years[235] away[236] which puts the economic benefits of the business case at risk. The Board agrees with UCG's submission[237] that the payback period is too long for such a small customer base, especially when one considers the rate at which technology changes. Furthermore, the Board shares the concerns of CW that until there is conclusive evidence either way regarding the imposition of TOU billing, proceeding with AMR at this time may result in additional risk to customers. Due to these concerns the Board is not prepared to accept the project and directs YECL to remove this project and its costs from rate base. The Board further directs YECL to reflect this finding in its compliance filing.

10.8.2 Watson Lake bi-fuel project (Business Case #6)

Phase 1 of this project calls for the modification of Unit #5 at Watson Lake's power plant to a bi-fuel system, which allows the unit to run on a combination of diesel and natural gas. The purpose of this phase is to verify that natural gas injection into the engine provides reliable electricity generation for a utility power system in addition to the

[233] CW Final Argument, paragraphs 43 to 45.
[234] YECL Reply Argument, paragraph 114.
[235] The Board, in Order 2009-02, Appendix A: Reasons for Decision, noted the nine-year cross-over of the benefits at that time; page 42 of 49.
[236] Information Responses, UCG-YECL-125(h).
[237] UCG Final Argument, paragraph 290.

environmental benefit of reduced emissions. YECL submitted that Phase 2 of the project, scheduled for 2014 — assuming the success of Phase 1 — will see the conversion of the remaining five units at the Watson Lake power plant to bi-fuel operation. As natural gas is currently unavailable through direct pipeline, YECL submitted that the fuel will be supplied by a truck transporting liquefied natural gas (LNG) to the Watson Lake power plant. YECL pointed out that the availability of LNG allows for reduced emissions and indicated that through the project, YECL was pursuing a 50-percent displacement, on average, of the amount of diesel fuel normally used. YECL also submitted that in addition to the environmental benefits, the project will assist in determining the operational and financial benefits of LNG as an alternate fuel source for electricity generation. [238]

In its updated forecast, YECL submitted that due to delays in receiving permits and licensing approvals for the Watson Lake bi-fuel project, Phase 1 of the project, originally scheduled to be completed in 2013, has been delayed until 2014. Accordingly, the 2013 capital costs have been moved to 2014, and the storage and vaporization charges from ATCO Gas, included in O&M expenses, are now forecast to begin in September 2014. YECL also explained that the deferred charges related to the bi-fuel project are now to be amortized beginning in 2014, rather than 2013.[239]

YECL stated that the primary driver for the project was to provide local emission reductions while the economic driver was fuel savings. YECL submitted that when "the lease cost of $22,000 per month is included in the project operations and maintenance costs, cumulative fuel savings begin in 2017… [Furthermore, when] comparing the project capital costs to the cumulative fuel savings, a simple project payback of 9 years is shown."[240]

Respecting its diesel generation account, YECL submitted that 2013 and 2014 forecast cost increases were mainly due to lease costs for LNG facilities at Watson Lake.[241] YECL explained that it took the lease approach to secure an inclusive provider of natural gas rather than a consortium of consultants, equipment providers and specialized service providers. YECL submitted that:

> This bundled approach with ATCO Gas to provide natural gas includes LNG storage and vaporization services along with their expertise related to systems design, purchasing, installation, commissioning, operations support, maintenance, permitting, regulations and safety. The equipment being utilized is secured utilizing ATCO Gas' competitive procurement process that involves engineering, financial and purchasing professionals.[242]

YECL also stated that a competing lease provider was not in the market at the time to meet the needs of the Watson Lake project in 2012.

[238] YECL Application, Business Case #6, page 2 of 4.
[239] YECL updates filing, October 31, 2013, page 5 of 9.
[240] YECL Final Argument, paragraph 108.
[241] YECL Application, Schedule 5.2, page 1 of 5.
[242] Information Responses, YUB-YECL-6(i)

For purposes of the pilot project, YECL submitted that the lease option was prudent as it does not require YECL to invest upfront in the equipment, and it allows flexibility for exiting the project if the pilot is not successful. Moreover, since the lease arrangement also includes ongoing services for O&M in addition to equipment supply, YECL submitted that if the market develops whereby the equipment and specialized services become more costly going forward, the lease arrangement provides additional cost certainty for the project to achieve fuel cost savings related to diesel.[243]

YECL pointed out that there is very little cost difference between leasing and purchasing over the long term. Furthermore, the lease approach is already demonstrating benefits as it is ATCO Gas that is bearing the risk associated with the delay in this project;

> It has given Yukon Electrical a lease rate, as detailed in the Liquefied Natural Gas Services Agreement, and has bought the equipment, but services are not going to be provided until 2014 now. Lease payments do not become due until the service is being provided.[244]

YECL submitted that the bi-fuel project has been the subject of a review under the *Yukon Environmental and Socio-Economic Act* and a decision document issued in August 2013 supporting the project, which is now being reviewed for permitting and licensing. YECL submitted there will be meaningful reductions in the emission of particulate matter, SOx and NOx and there will be associated health benefits of such reductions.[245]

YCS submitted that the Watson Lake bi-fuel project is a fossil fuel substitution to create a market for natural gas in Yukon. Furthermore, it will present an obstacle to the development of renewable energy in Yukon's diesel communities. YCS pointed out that despite there being technologies to make diesel generators less polluting, YECL has not installed them. YCS asserted that proceeding with the Watson Lake bi-fuel project would defer the development of renewable energy and negatively affect the evaluation of renewable energy development in other diesel communities in Yukon.

> Entrenching our system in LNG would present a false economic obstacle to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low.
>
> …
>
> As an example … a wind farm developer would have to compete with the predicted lower, avoided cost of LNG rather than the present higher avoided cost of diesel.[246]

YCS therefore recommended that, because the Watson Lake bi-fuel project is a pilot project that would obstruct the development of renewable energy solutions, and

[243] Information Responses, CW-YECL-8(b).
[244] YECL Final Argument, paragraph 110.
[245] YECL Final Argument, paragraph 111.
[246] YCS Final Argument, page 4 and 5.

because YECL cannot prove that the net emissions will be of benefit, the project should not be allowed into rate base.[247]

YECL replied that there is no evidence respecting the YCS assertion that the project will defer and obstruct the development of renewable energy solutions. YECL added that, as the evidence shows, it is pursuing a broad range of technologies to provide energy alternatives for ratepayers. YECL submitted that the bi-fuel project uses technology that provides firm capacity and is available now to provide savings to ratepayers. Furthermore:

> Energy displacement technologies (non-firm capacity) such as wind and solar can be utilized with diesel and bi-fuel systems to reduce fuel requirements if the financial challenges can be overcome. However, the need will remain to provide firm capacity to deliver electricity when the wind is not blowing or the sun is not shining. A firm backup supply of electricity provided by the existing generating facility is anticipated to be required for the renewable options that are being investigated. [248]

Accordingly, YECL submitted that the Watson Lake bi-fuel project is needed and will be complementary to the renewable options that are being investigated.

UCG submitted that all costs related to the Watson Lake bi-fuel project should remain in WIP until "the project is completed and deemed used and useful following a comprehensive prudency review of actual costs incurred and validation of benefits to be realized."[249] After noting that $500,000 is the major project threshold, UCG asserted that the $1-million threshold should be reviewed as part of a significantly more comprehensive review process,[250] than is afforded with a GRA. Accordingly, UCG submitted that all costs related to the Watson Lake bi-fuel project should remain in WIP until the project "is completed and deemed used and useful following a comprehensive prudency review of actual costs incurred and validation of benefits to be realized."[251]

YECL, replying to UCG, submitted that it has diligently detailed the need and prudence of its capital projects as part of the record of this Application. Moreover, the Yukon government has not designated any of YECL's forecast 2013 to 2015 capital projects, including the Watson Lake bi-fuel project, as regulated projects pursuant to Part 3 of the *Public Utilities Act.* Considering the large amount of evidence on the record in respect of this project, YECL submitted that a GRA is the appropriate place and process to test projects. Furthermore, the "introduction of a Part 3 process would create needless duplication and regulatory inefficiencies."[252]

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[247] YCS Final Argument, page 5.
[248] YECL Reply Argument, paragraph 115.
[249] UCG Final Argument, paragraph 51.
[250] UCG referenced a Board report, wherein the Board stated that, given the smaller number of ratepayers in Yukon, a $1-million threshold would be appropriate for capital expenditures to be reviewed as part of a more comprehensive process, i.e. Part 3 of the *Public Utilities Act*.
[251] UCG Final Argument, paragraph 269.
[252] YECL Reply Argument, paragraph 122.

LE suggested that, considering the evidence on the record, environmental benefits related to this project are arguable at best. Furthermore, from LE's perspective, the projected cost savings related to bi-fuel operations are optimistic.

> In Europe and Asia LNG costs are 3 to 4 times the cost in Canada, and once export systems are in place Canadian LNG costs will likely increase to export values.[253]

Although there is a potential cost saving argument to be made based on present Canadian LNG pricing, LE is not in favour of the Board approving the Watson Lake bi-fuel project. However, should the Board approve Phase 1 of the project, LE is not in favour of proceeding with Phase 2 of the project "without YECL coming back to the Board and the public with actual environmental data and updated cost and cost saving projections."[254] LE further submitted that all capital and operating costs beyond the equivalent for a diesel only operation should be held in a work-in-progress account so that "if the project is not successful the ratepayers do not pick up the costs. Financial savings over and above diesel only operation, if any, can offset the cost accumulated in the account."[255]

Responding to LE argument, YECL submitted that environmental benefits have been recognized through the YESAB review process as being viable for the bi-fuel project. Moreover,

> …the reduction of the following emissions will result from the bi-fuel project; particulate matter, important to people with comprised lung function, and NOx and SOx, contributors to smog and acid rain.[256]

YECL further submitted that LE had not provided evidence to contradict the forecast LNG and diesel cost information. Furthermore, YECL's $1.7 million projected savings by 2023, are based on forecast from a respected industry expert. In summary, LE has not provided evidence to substantiate its claims that the environmental or cost benefits associated with the bi-fuel project will not be realized; the project is needed and will result in material savings as well as meaningful reductions of particulate matter.[257]

In argument, CW submitted that it had several concerns with YECL's proposed lease agreement with ATCO Gas. First, CW submitted that it was concerned that no purchase option of the equipment is available because if the pilot is successful and YECL continues the use of the LNG storage, vapourization equipment and associated services from ATCO Gas, the higher lease rate will continue. CW submitted that if the pilot is successful, and it is more economical for YECL to own the assets, a purchase option should be available to YECL. Second, CW was concerned about the contract including a provision for an inflation increase in the price for each year. CW stated that the lease is for vapourization equipment, which is a hard asset. Once the asset is purchased, the costs are fixed, and there is no need for any inflationary increases in prices. Third, CW

[253] LE Final Argument, page 8.
[254] LE Final Agreement, page 9.
[255] LE Final Argument, page 9.
[256] YECL Reply Argument, paragraph 116.
[257] YECL Reply Argument, paragraph 117.

submitted that ATCO Gas is a regulated utility in Alberta, yet the return embedded in the lease rates is 10 percent, which is higher than the regulated return on equity of 8.75 percent in Alberta. Fourth, CW submitted that the project has been delayed until 2014. As such, the costs included in revenue requirement should be removed from 2013, and the 2014 revenue requirement should be adjusted to accommodate the change in implementation dates.

In response to CW's recommendation that the costs included in 2013 revenue requirement should be removed and the 2014 revenue requirement adjusted, YECL submitted that it had already adjusted its 2013 and 2014 revenue requirements to account for the delay in the project. These adjustments were presented as part of the updates filing submitted on October 31, 2013.

In response to CW's suggestion that inflationary increases over the 20-year term of the lease should not apply to the lease of the storage and vaporization equipment, YECL submitted that the lease agreement with ATCO Gas is based on fair market value. Based on other equipment YECL is leasing from third party suppliers, lease arrangements for assets commonly include some sort of escalation. YECL also noted that, for the test period, the amount of the lease payments included in revenue requirement is constant at $22,000 per month, so the issue of inflation of the lease payments has no bearing on the test period.

With regard to ATCO Gas' rate of return for the lease, YECL submitted that the utility rate of return for Alberta is not an appropriate measure against which to assess the prudence of the lease arrangement because the equipment being leased and the services being provided are separate from ATCO Gas' regulated utility operations.

With regard to the lease agreement including a purchase option, YECL noted that the lease arrangement, filed as UCG-YECL-21(g) Attachment 15, includes both a termination clause, allowing the lease to be terminated with12-months' notice, as well as a purchase option. YECL submitted that the structure of the lease arrangement as written provides the flexibility required for YECL to make prudent and cost-effective decisions in the future related to bi-fuel operations in Watson Lake. YECL submitted that CW's recommendations regarding the lease arrangement with ATCO Gas should be rejected.

10.8.2.1 Views of the Board

The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period."[258] The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."[259]

[258] November 4, 2013 transcript, page 86, lines 6 to 9.
[259] Information Reponses, CW-YECL-8(b).

The Board has reviewed the concerns put forward by CW and finds that the concerns have been adequately addressed by YECL in its updates filing and reply argument.

The Board takes note of YECL's submission that when comparing the project capital costs to the cumulative fuel savings, a simple project payback of nine years was shown.[260] However, in the same intervener request, YECL pointed out that a competitive market for LNG supply did not yet exist as there was only one Western Canadian supplier of LNG at the time, albeit two other suppliers were expected to be in the market in 2014.[261]

The Board has taken into account the lack of a competitive tendering process as evidenced by YECL's submission that a "competing lease provider was not in the market at the time to meet the needs of the Watson Lake project in 2012."[262] However, YECL submitted that YECL had full visibility into the:

> …competitive process for the storage vapourization equipment… and are working with ATCO Gas under the conditions of a fair market value arrangement then with what we'll provide with respect to the pricing components that are within that various components for the equipment and for the services that are being provided and for a return on the project.[263]

In the Board's view, fair market value is best determined through a competitive tender process. In this case, the lack of such a process leads the Board to question the costs of the proposed project. The Board considers that the markup in determining the lease price appears high.

Based on the above, the Board rejects YECL's proposal to include the Watson Lake bi-fuel project in its rate base. The Board therefore directs YECL in its compliance filing to reflect the removal all project-related costs from its proposed capital additions. YECL is to handle the related study costs as directed in Section 10.2.1 of this decision.

10.8.3 Carcross 2 MVA standby project (Business Case #12)

This project includes the purchase and installation of a 2-MW self-contained generating unit for contingency in the Carcross substation at a total cost of $3 million. YECL proposed that the unit be equipped with synchronizing capability, connected via a three-phase step-up transformer and associated protection to the distribution system. YECL also proposed that the unit be connected to the SCADA system.

In Board Order 2009-2, the Board denied YECL's proposal to include the Carcross diesel unit in YECL's rate base stating that it was not convinced that the Carcross generator was the best option at the time. The Board directed YECL in its next GRA:

> …to present its business case respecting the Carcross genset if it is still the preferred option to mitigate reliability concerns in the area.

[260] Information Responses, YUB-YECL-42(a).
[261] Information Responses, YUB-YECL-42(d)(i).
[262] Information Responses, YUB-YECL-6(i).
[263] November 4, 2013 transcript, page 89, lines 6-14.

> … [and] to present industry recognized statistics that affirm the success of its projects and program initiatives that have safety and reliability as their basis.[264]

In response to the Board's directions, YECL submitted that it undertook further analysis with regard to the need for a dedicated standby generation unit for the communities of Carcross and Tagish. In view of the analysis, YECL provided a business case[265] in support of the project and submitted that the project was necessary based on N-1 criteria. YECL submitted that:

> The rationale for a threshold minimum load of 1.0 [MW] to enact an N-1 planning criteria is based on the January 2006 Yukon Energy Corporation 20 Year Resource Plan…
>
> > …Each grid system … will be planned to be able to carry the forecast peak winter loads (excluding major industrial loads) under the largest single contingency (known as "N-1"). The N-1 criterion determines system capacity assuming the loss of the system's single largest generating or transmission-related source.
> >
> > …For communities … any location with a load large enough to justify a diesel unit of 1 MW or more will be considered as a preferred location for new diesel units if that community does not already have back-up from another source e.g., having an existing diesel unit). The new diesel units would provide grid support, and in times of line failures would provide local generation for the communities where they are located.[266]

YECL proposed a threshold minimum load of 1 MW and 300 customers to enact the N-1 planning criteria. The 300-customer recommendation was recommended as a minimum community size for locations with sufficient load that benefits a reasonably high number of customers.[267] YECL pointed out that the communities of Carcross and Tagish, including the surrounding areas, have peak load demands of 1.5 MW in the winter with approximately 712 customers. YECL also provided industry standard outage and reliability statistics in support of the project.[268] Moreover, YECL added that it had "considered a number of alternatives, but has determined that the optimal solution to improve service reliability is a standby generator."[269]

YEC indicated that it was addressing the need for new thermal generation units on the grid to replace existing diesel units that needed to be retired and pursuing opportunities for conversion of diesel units to lower cost and lower emission LNG-supplied gas-fired units. As primary generator and transmitter on the grid, YEC submitted that prior to establishing any new thermal units at locations on the grid where no such units currently exist, there is a need for YECL to consult with YEC in order that options and potential

[264] Board Order 2009-2, pages 38 and 39.
[265] YECL Application, Business Case #12, Carcross 2 MVA Standby Project.
[266] Information Responses, YUB-YECL-46(a).
[267] Information Responses, YUB-YECL-46 (a).
[268] Information Responses, YUB-YECL-46 (d), Attachment 1.
[269] YECL Final Argument, paragraph 95.

future plans and requirements for the grid can be fully considered and the Board can be advised accordingly.[270]

YECL replied that it had consulted with YEC with respect to this project. Furthermore, plans "to progress with the project were discussed with YEC and the Yukon government in January 2013."[271] Accordingly, YECL submitted that YEC's submission should be rejected. YECL reiterated that the communities of Carcross and Tagish, on average, experience a higher incidence and duration of outages than other communities served by YECL. YECL pointed out that the indices, provide as part of YUB-YECL-46(d)(i) Attachment 1, indicate that reliability of supply can vary significantly over time. Furthermore, it is evident from the community that residents, businesses and emergency responders in the Carcross and Tagish areas consider that a standby unit is essential. Considering the above, YECL submitted that the need for this project has been demonstrated and it should be approved as filed.[272]

10.8.3.1 Views of the Board

The Board notes YECL's submission that "[t]he line to Carcross and Tagish has not been identified as a particular problem area."[273] The Board also takes note that the right of way has been widened as stated above and that some sections of line have been rebuilt along the road-side right of way which, according to YECL, removes the trees entirely from the road-side of the power line and speeds up patrolling/trouble shooting times. The Board took into account the outage and reliability statistics in support of the project provided by YECL and the YECL submission that reliability of supply can vary significantly over time.

After weighing the different factors, the Board is not convinced that a $3-million expenditure for the purchase and installation of a 2-MW generating unit to be used for contingency purposes is justified. The Board suggests that YECL look at partnering with YEC respecting the possibility of a cost-effective mobile generating unit or other alternatives that may prove beneficial for providing system wide support.

As a result, the Board rejects YECL's proposal to include the Carcross 2-MW standby generating unit project in its rate base. Accordingly, the Board directs YECL in its refiling to reflect the removal of the proposed Carcross diesel unit from its proposed capital additions.

Regarding the proposed threshold minimum load of 1 MW and 300 customers to enact the N-1 planning criteria, the Board considers that YECL's interpretation of the approved N-1 criteria for grid-connected communities is incorrect because for each grid-connected community the determination of the need for backup generation is to be considered on a case-by-case basis. For this reason, the Board rejects YECL's proposal to enact a threshold minimum load of 1 MW and 300 customers.

[270] YEC Final Argument, page 23.
[271] YECL Reply Argument, paragraph 118.
[272] YECL Reply Argument, paragraph 119.
[273] Information Responses, YUB-YECL-46 (d).

10.8.4 Significant capital projects

In Board Order 2009-2, the Board directed "YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."[274] YECL submitted that it had provided business cases for all major capital projects — i.e. projects greater than or equal to $500,000, as directed.[275] Additionally, YECL provided write-ups for projects greater than $100,000.[276]

With respect to the Watson Lake bi-fuel project, UCG pointed out that YECL had only provided a high-level summary breakdown of the study costs incurred without providing details. In addition, YECL had not met the burden of justifying the recovery of these costs prior to the in-service date of the proposed Watson Lake bi-fuel project.

UCG submitted that a $4-million project such as the Fish Lake unit #1 capital program should be reviewed pursuant to Part 3 of the *Public Utilities Act* and the Board should direct YECL to seek approval to have this project reviewed pursuant to Part 3.

YECL, replying to UCG, submitted that it has diligently detailed the need and prudence of its capital projects as part of the record of this application. Moreover, the Yukon government has not designated any of YECL's forecast 2013 to 2015 capital projects, including the Watson Lake bi-fuel project, as regulated projects pursuant to Part 3 of the *Public Utilities Act.* Considering the large amount of evidence on the record in respect of this project, YECL submitted that a GRA is the appropriate place and process to test projects. Furthermore, the "introduction of a Part 3 process would create needless duplication and regulatory inefficiencies."[277]

10.8.4.1 Views of the Board

With respect to UCG's submission that the Fish Lake unit #1and the Watson Lake bi-fuel capital projects be reviewed pursuant to part 3 of the *Public Utilities act*, the Board notes that the Minister has not designated either of these projects as a regulated projects. Moreover, the Board cannot designate the projects as such. Accordingly, the Board rejects UCG recommendation.

11 INCOME TAX

YECL uses the flow-through method in calculating its income tax expense. Under this method, YECL calculates the income tax expense based on taxable income which is minimized by claiming the maximum of all available deductions. Deferred taxes are not booked by YECL[278]. The following reflects forecast income tax expenses for YECL:

[274] Board Order 2009-2, Appendix A: Reasons for Decision, page 37 of 49.
[275] YECL Application, page 9-4.
[276] November 5, 2013 transcript, page 315, line 11.
[277] YECL Reply Argument, paragraph 122.
[278] YECL Application, page 10-1.

Table 23. **YECL Forecast Income Tax Expense**

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	Test 2013	Period 2014	2015
				($000)				
Income Tax Expense	(94)	10	278	61	(307)	248	704	828

In response to UCG-YECL-96(a), YECL stated that part of the increase in income tax is explained by the growth in rate base and the increase in the equity ratio from 40 percent to 44 percent.

No issues regarding income tax were identified in this proceeding.

11.1 Views of the Board

The Board accepts the methods YECL has used to calculate income tax and directs YECL to use these methods when it calculates income tax in its compliance filing.

12 YUKON FIVE-YEAR DEMAND SIDE MANAGEMENT PLAN

In its Reasons for Decision in Appendix A to Board Order 2009-02 and Appendix A to Board Order 2009-08, the Board directed YEC and YECL to develop a policy paper with respect to Demand Side Management (DSM) initiatives. More specifically, the directions were as follows:

> **From Appendix A to Board Order 2009-02**
>
> The Board views DSM as another critical issue for Yukon. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory.
>
> **From Appendix A to Board Order 2009-08**
>
> Furthermore, the Board finds DSM to be a critical issue for all electric rate payers in Yukon. The Board directs YEC in conjunction with YECL, to consult with stakeholders and develop a policy paper with respect to DSM initiatives. YEC and YECL are to jointly lead this process and submit a policy paper (Plan) in their next GRA. Further the utilities are to be cognizant of and work with ESC where necessary so as not to duplicate efforts.

> The Plan should include initiatives developed through negotiations with intervenor groups and communities in the Yukon. The Plan should provide a wide range of energy efficiency and conservation measures that will assist ratepayers in dealing with the high cost of energy in the Yukon and also provide support for local initiatives identified through community energy planning initiatives.
>
> The Board finds the UCG and LE proposals for deferral accounts in support of the DSM initiatives acceptable and both YEC and YECL can propose appropriate treatment of these accounts at the time of their next GRA.

In the Application, YECL submitted that in partnership with YEC, YECL has developed a five-year plan (2013 to 2018) to implement and measure DSM programs for Yukon. To develop a plan for the territory, YECL and YEC (Utilities) formed a joint committee with additional representation from the Government of Yukon (GY) to examine DSM. The joint committee determined that the required baseline data was not available to pursue a DSM plan. From January 2011 through to April 2012, the Utilities and GY worked cooperatively to develop the Conservation Potential Review (CPR) for Yukon to determine the feasibility of DSM savings for ratepayers.

The CPR outlined that growth in the residential and commercial sector could increase by 65 percent over the next 20 years and that electricity conservation could provide up to 35 percent savings of the new growth. Based on this information, the Utilities determined that DSM was a feasible new generation option and continued toward the development of the five-year DSM plan. The plan was developed by the Utilities in collaboration with interveners, Yukon non-government organizations, community leaders, First Nation governments and the general public.

YECL stated that the Utilities committed to an electricity conservation target of 8.5 GWh of sustained savings by the end of the fifth year of the established DSM programs. This goal was identified based on the results of the CPR. To meet the identified goal, the Utilities developed the five-year DSM plan and identified the following program areas for residential and commercial customers:

Residential

- Appliances and lighting
- Low-cost, easy-to-install measures including low-flow showerheads and pipe insulation, programmable thermostats
- Technologies providing significant potential savings but requiring further performance proofing in Yukon conditions
- New home constructions

Commercial

- Lighting including: LED, high performance T8, pulse start MH, high output T5
- Building optimization – operations and HVAC
- Refrigeration and computer equipment

YECL stated in the Application that a Program Implementation Plan (PIP) was also developed, which includes the following sub-plans:

(1) Operation Plan – work plan to develop process flows, procedures, forms, etc. Develop guidelines for participants, delivery channels, trade allies, etc.
(2) Human Resource Plan – staffing definitions, recruitment strategies, internal staff capability development.
(3) Marketing & Communication Plan – communication strategy, key messages, plan for public relation activities, ongoing market research activities to test effectiveness of the strategy.
(4) Program Tracking System – terms of reference for the procurement of program tracking software and hardware for the development of an in-house system.
(5) Financial Plan – detailed budgets including program costs forecast and incentive expenses forecast, updated cost-effectiveness tests.
(6) Evaluation, Measurement and Verification (EM&V) Plans – description of program theory, program logic. Evaluation requirements for process, impact, market effect evaluations.

YECL stated that these components represent the five-year DSM plan for Yukon and will deliver to the ratepayer a set of ready-to-launch programs for the General Service and Residential sectors designed to deliver the sustained savings target of 8.5 GWh by the end of the five-year DSM program cycle.

YECL noted in the Application that the Utilities had agreed that large industrial customers would be addressed separately from the five-year DSM program since it is more practical to work directly with these customers. However, savings resulting from industrial programs conducted by either or both utilities will be calculated toward the goal of 8.5 GWh by the end of the five-year DSM program cycle.

In the response to information request YUB-YECL-24, YECL submitted detailed actual costs spent in 2011 and 2012 for DSM and detailed forecast costs for 2013, 2014, and 2015. YECL also submitted that it planned on capitalizing all DSM costs; however, it had inadvertently included DSM costs in both capital and O&M in the amounts of $88,000 for 2013, $90,000 for 2014 and $92,000 for 2015. YECL also noted in that information response that it would rectify the error in its compliance filing.

In its updates filing, submitted on October 31, 2013, YECL submitted that the DSM costs presented in Business Case #30 included the costs of two positions that it had accidently excluded from the employee FTE complement presented in the Application. More specifically, YECL submitted that it planned to add both a Customer Engagement Officer and a Back Office Coordinator in 2014. Therefore, including these two FTEs, YECL's forecast ending complement for 2015 should be 75.39.

During the oral hearing, the Utilities presented a joint panel between YEC and YECL to answer questions regarding DSM. The witnesses included as part of the DSM panel were as follows:

Table 24. **DSM Panel**

Name	Title
David Morrison	President & CEO, YEC
Stephanie Whitehead	Energy Conservation Coordinator, YEC
Dwight Redden	General Manager, YECL
Laura Carlson	Senior Corporate Communications Advisor, YECL
Judy Simon	Principal, ICF Marbek
Paul Robillard	Director, ICF Marbek

In response to DSM Undertaking #7, both YEC and YECL submitted estimates of the total costs spent, and forecast to be spent, by each utility on DSM-related activities, minus the cost related to the development of the plan or the policy paper, from 2011 to 2018. The information is summarized in the table below.

Table 25. **DSM Costs incurred by YEC and YECL (excluding costs related to DSM plan development)**

Year	YECL ($)	YEC ($)	Total ($)
2018	842,000	770,000	1,612,000
2017	732,000	663,000	1,395,000
2016	792,500	726,500	1,519,000
2015	730,000	650,000	1,380,000
2014	522,000	472,000	994,000
2013	105,000	385,000	490,000
2012	4,000	309,164	313,164
2011	47,000	215,216	262,216
Total ($)	3,774,500	4,190,880	7,965,380

In response to DSM Undertaking #8, YECL submitted that the joint utility plan expects savings of 9.3 GW.h after the completion of the fifth year of the filed plan. When calculating the savings, the Utilities used the avoided cost of new generation to determine the value of the 9.3GW.h. The avoided cost of new generation is $0.21 KWh. Therefore, the total avoided new generation savings by the end of year 5 of the DSM plan is $1,953,000.

In argument, YECL submitted that, in response to the Board's direction, YECL had worked with YEC and independent experts for over two and a half years to develop the DSM plan. YECL stated that it had fully addressed the Board's direction and provided a wide range of energy efficiency and conservation measures that will assist ratepayers in dealing with the high cost of energy in Yukon. YECL argued that the costs associated with the DSM plan are reasonable and should be approved as filed.

YECL further stated that the DSM plan, including the CPR and program portfolio, as well as the PIP and EM&V plan were all prepared by independent experts at ICF Marbek using concepts proven in other jurisdictions. YECL submitted that these concepts have not only shown reductions in the consumption of electricity in other jurisdictions, but have shown reductions at costs that are considerably cheaper than new supply. More specifically, YECL reiterated that, as outlined in YECL's response to

DSM Undertaking #3 and DSM Undertaking #8[279], cumulative electricity savings of 240 MWh, 1,487 MWh, and 9.3 GWh are expected after completion of the first year, second year, and fifth year of the DSM plan.

With regard to stakeholder consultation, Mr. Robillard, YECL's witness on DSM, noted during the hearing that, in his view, the stakeholder participation in the development of the DSM plan had been in the top 10 percent of any process that he had been involved with. YECL also submitted that there will be opportunities for continued stakeholder input through the EM&V process, which will be undertaken throughout the program delivery.

YECL argued that, while a number of the interveners appeared to take issue with certain program offerings that have not been included in the first iteration of the DSM plan, none appeared to suggest that the DSM plan should be abandoned. Furthermore, as explained by Mr. Robillard, as DSM is in its infancy in Yukon, the objective was to begin with measures that the Utilities could be sure they would do well with and avoid beginning with programs that may be overly complex.

YECL also submitted that programs targeted at low-income customers or at peak shifting are matters that can be considered in future iterations of the DSM plan, once the Utilities have trained their staff and have a better understanding of their market.

YECL requested that the DSM plan and the costs associated with the development and implementation of the DSM plan, as outlined in Business Case #30, be approved by the Board as filed.

In argument, YCS submitted that it supports the DSM plan; however, YCS noted that it believes the plan to be inadequate. YCS recommended that the Board direct that future iterations of the DSM plan be aimed clearly at specifically reducing the use of fossil fuels and maximizing renewable energy by shifting loads, particularly those of hot water heating and space heating.

In argument, LE submitted that in its view, the Utilities have spent more time and money than necessary to develop a DSM plan but failed to make it aggressive enough with regard to matters besides basic conservation, including peak shaving, load shifting, and valley filling. Despite its shortcomings, LE recommended that the Board approve the joint DSM plan and Business Case #30. LE also recommended that the Board direct YECL and YEC to implement additional DSM measures that include some or all of peak shaving, load shifting, valley filling, and surplus hydro sales starting not later than at the start of the fourth year of the DSM program.

In argument, CW submitted that YECL had confirmed during the hearing that some of the costs forecast in relation to DSM may vary depending on uptake — e.g. YECL may spend less than forecast if less people than the Utilities have projected participate in various DSM initiatives. The Utilities also confirmed that, in the event that there is greater uptake than forecast, the Utilities' budgets will be respected and opportunities

[279] 2013-11-13 YECL Undertakings

may cease in a particular year if the budget has already been expended. CW argued that the risk in this case is one-sided. If the actual amounts spent on DSM are less than forecast in any year, the Utilities stand to benefit; however, if interests in the DSM programs are higher than expected, the Utilities have the control to limit the number of participants and ensure that the actual amount spent on DSM is not more than forecast in any year of the five-year plan.

CW added that it is concerned that the level of uptake and the costs associated therewith cannot be as reasonably or reliably forecast as other costs. CW stated that it believes that these costs should receive deferral treatment for the test period to ensure that customers are only responsible for costs actually incurred for DSM programs. More specifically, CW submitted that both utilities should be directed to give deferral treatment to all DSM costs for each utility's respective test period.

In argument, UCG put forward a number of concerns and recommendations with regard to the DSM plan.

UCG submitted that YEC's role in the proceeding was unclear. More specifically, YECL had not finalized the specific DSM witnesses until October 30, 2013 and therefore, the Board and interveners did not know YEC would be on the DSM panel until October 30, 2013. UCG stated that if proper advance notification had been provided, YEC would present witnesses, information requests could have been submitted to YEC in line with the proceeding schedule in order to get additional information on the record without having to take up additional hearing time. UCG argued that as it occurred, it was unclear during the hearing why YEC was responding to questions for which parties were looking for responses from YECL. UCG further submitted that while the Board has not been asked to approve any of YEC's DSM-related costs, YEC's spending on DSM initiatives must be taken into account in order to understand the burden that Yukon ratepayers are being asked to absorb now and in the future with respect to the DSM programs being delivered jointly by the Utilities. UCG recommended that in its decision, the Board specifically indicate that any DSM-related expenditures that have been made by YEC to date or that will be made in the future must continue to be tracked in a deferral account for DSM O&M-related costs, and WIP for all DSM-related capital costs, as directed in Board Order 2013-01, until such time as YEC brings forward an application to include the recovery of prudently incurred DSM costs in rates charged to Yukon ratepayers.

UCG added that according to YECL's Senior Corporate Communications Advisor, the Utilities are currently continuing their joint effort to prepare for the launch of DSM programs in the second quarter of 2014 upon the approval of the program by the Board. However, based on the evidentiary record, UCG argued that it is premature to determine when proposed DSM programs will be launched. UCG recommended that the Board should direct the Utilities to ensure the separation of DSM program components from general marketing activities so that all DSM-related costs can be treated in the same way.

UCG was also concerned that the Utilities appeared to have made no attempt to optimize the DSM plan and provided little detail on the programs to be delivered, the

mechanics of delivering these programs, and the impact that these programs will have on the bills paid by ratepayers.

UCG stated that one of YECL's DSM consultants, during her time as a member of the Ontario Energy Board (OEB), ruled that acceptable rate and bill impacts resulting from DSM programs was an appropriate objective of a DSM plan and that the acceptable rate impact should be fine-tuned after the post-delivery assessment of DSM programs and portfolios. In that same decision, the OEB panel directed the utility to provide evidence of the avoidance of building additional facilities due to DSM initiatives and stated that in order to screen DSM programs, it is necessary to determine the costs which are being avoided through demand-side reductions in load. UCG submitted that the expected results of DSM programs must have a corresponding impact on supply-side plans. The expected volumetric effects of all adopted DSM programs, including test-marketed programs, should be included in the Utilities' demand forecasts. The impact on rates resulting after evaluating all programs in the DSM portfolio must not impose an undue burden on existing customers. Both short-term and long-term rate impacts should be considered.

UCG contended that while the report by ICF Marbek refers to avoiding the cost and environmental impact of building new generation and the avoided cost of supply, there is no information on the record about how the avoided cost threshold levels were determined. UCG argued that the appropriate approach to determining the value of demand-side options is an avoided cost methodology where avoided costs include utility capital, operating and energy supply costs, monetized environmental and societal externality costs, and incremental or decreasing customer equipment and operating costs.

UCG disagreed with the criteria used in the proposed DSM plan, to determine the economic potential and achievable potential results for DSM initiatives in the residential and commercial sectors.

UCG argued that, as in other jurisdictions, avoided costs provide the only practical means of comparing DSM programs. The use of avoided costs would permit comparisons to supply-side options. The use of long-run avoided costs as inputs for the cost-effectiveness tests would allow the Utilities to evaluate their DSM programs and compare them fairly with supply-side options. UCG submitted that a key consideration of the value of a DSM plan is whether it reduces a utility's supply-side requirements. UCG argued that the Utilities have purposely focused the DSM programs on the customer side of the meter and have not considered system efficiencies as part of the measurement, evaluation and ranking of proposed DSM programs.

UCG stated that, as a result of their screening of potential DSM programs, the Utilities determined that there were three program elements for residential ratepayers. It argued that a low-income ratepayer will not be able to make additional purchases of LED lights, block heater timers or heat pumps when they are already having difficulties paying their bills, including ever-increasing electricity charges. UCG added that, the Utilities testified that they have not considered how they might target DSM programs to low-income ratepayers or ensure that low-income is not a barrier to participating in proposed DSM

programs. UCG argued that identifying those eligible for low-income DSM programs can be as simple as ensuring that applicants for these programs meet a specific income threshold — depending on the number of people in the house — or, if they receive government payments related to programs such as a disability support program, guaranteed income supplement, an allowance for seniors or the national child benefit.

UCG contended that the Utilities have effectively excluded the low-income ratepayers from being able to participate in proposed DSM programs for which they will be paying through their electricity bills. UCG submitted that the proposed DSM plan and resulting programs should not be approved until the Utilities come back with programs that are geared toward low-income ratepayers along with details of the associated budget and that the Board should direct the Utilities to ensure that a percentage of the annual DSM budgets — e.g. 15 percent — is targeted toward low-income ratepayers.

With respect to the internal DSM programs conducted within the Utilities themselves, UCG argued that a significant portion of the costs should be recovered from the shareholder who benefits; however, it is not clear how much of the total cost of these programs are to be recovered from the shareholders. UCG pointed to Business Case #29 — Downtown Office Building Envelope Upgrades. It stated that that it is unclear why expenditures on continual improvement initiatives should be using up any portion of a finite DSM budget designed to deliver programs to ratepayers. UCG added that all costs associated with expenditures on continual improvement or DSM on the Utilities' own facilities should be captured within the non-DSM budgets of the Utilities.

UCG was concerned about the quality of the consultation process that was carried out by the Utilities for the development of the DSM plan. It argued that the consultative process used by the Utilities on their proposed DSM plan could have been improved if it had begun earlier in order to allow interested parties more time for consideration and comment, by having wider participation including environmental groups, and by having a more generous shareholder funding mechanism to bring about more broad-based effective participation.

According to YECL's Senior Corporate Communications Advisor, the Utilities plan to submit annual DSM reports to the Board for information purposes. These reports are expected to contain, among other things, a budget for the upcoming year and any changes anticipated from the filed plan. Although the DSM program design proposes that budgets could be reallocated according to the program results, or new programs added if existing programs have not achieved the desired market penetration, the Utilities have committed that annual budgets will be respected.

UCG submitted that any DSM reports submitted by the Utilities to the Board should contain complete records of expenditures on DSM, amounts of electricity saved, and the benefits realized on the system as a whole, as well as a comparison to specific pre-set targets in each of these areas. As was advocated by YECL's consultant while a member of the OEB, UCG submitted that any DSM report should also address the fairness of a rate impact from DSM programs on customers who have already implemented conservation measures and alternate supply options on their own.

UCG submitted that ratepayers should not have to pay for the DSM program proposed by the Utilities until the actual costs incurred can be vetted in a prudency review. UCG submitted that YECL had testified that there remains a lot of uncertainty regarding whether the proposed DSM programs will attract subscribers and whether program budgets will need to be reallocated according to the program results. UCG further submitted that the lack of a deferral account would act as a disincentive for the Utilities to aggressively pursue DSM participation during the test years. UCG therefore recommended that the Utilities should be directed to track all DSM-related costs in a deferral account for DSM O&M-related costs, and Work in Progress for all DSM-related capital costs, pending a prudency review.

UCG elaborated that the recovery of all DSM-related costs should be deferred until (1) actual costs incurred can undergo a prudency review; (2) the review of the Utilities' pending Phase 2 cost allocation and rate design application can be completed; and (3) the Utilities apply to recover deferred costs as part of a general rates application.

In reply argument, regarding a deferral account for DSM, YECL responded to the intervener submission that when determining whether to request approval for the establishment of a deferral account, it uses the following criteria: (a) the costs are not under the control of the company and are not reasonably forecastable; or (b) an error in forecasting could produce a loss or gain of a substantial magnitude.

YECL submitted that DSM-related costs are under its control and do not meet the criteria for establishment of a deferral account. YECL added that it intends to capitalize all costs related to DSM. It had inadvertently included some DSM costs in O&M in the Application but subsequently corrected this in the updates filing. Therefore, YECL submitted that the recommendations by CW and UCG for deferral treatment of DSM costs should be rejected.

In response to LE's recommendation that the Utilities be directed to implement additional DSM measures and to UCG's suggestion that the DSM plan should not be approved until low-income programs are included, YECL reiterated that DSM is in its infancy in Yukon. The objective of the DSM plan was to begin with measures that the Utilities could be sure would do well and avoid beginning with programs that may be overly complex. YECL further explained that the programs proposed by LE and UCG require more consideration and market research before such programs can be rolled out. The Utilities did not want to slow down the process of getting a good initial suite of programs out into the market. Similarly, there was extensive discussion during the hearing in respect of programs targeted at low-income customers and how such programs are equally not good programs for a nascent DSM plan. YECL submitted that new initiatives can be considered in later iterations of the DSM program. Accordingly, YECL submitted that the LE and UCG recommendations in respect of peak shaving and low-income programs respectively, be rejected by the Board.

In reply to the UCG argument that the Utilities appear to have made no attempt to optimize the DSM plan, YECL submitted that the DSM program design process was an optimization process to select a portfolio of DSM programs and program elements that would optimize savings, while minimizing rate impacts. The optimization process was

based on the identification and fine-tuning of each of the programs and program elements based on the application of four standard cost-effectiveness tests, namely the total resource cost test (TRC), the program administration cost test (PAC), the rate-impact measure test (RIM), and the participant cost test (PCT). Details regarding the application of these tests are provided in ICF Marbek's report. By applying these standard tests, YECL submitted that the optimal balance was reached between expected volumetric effects, minimal short-term rate impact using the RIM test, and maximal long-term rate impact using the TRC test. YECL submitted that the results of these tests demonstrated that the programs and program elements adhere to the industry best practice regarding cost-effectiveness testing.

In response to UCG argument that there is no information on the record about what threshold levels were determined, YECL submitted that, as laid out in ICF Marbek's report, the four standard tests result in benefit-cost ratios that demonstrate success when they are above one, which means that the present worth of benefits outweighs the costs. Given the above and given the portfolio economics laid out in the ICF Marbek report, YECL argued that the DSM portfolio presented complies with cost-effectiveness principles. YECL submitted the DSM programs are going to be targeted to specific customer groups to realize certain benefits and will also result in avoided system costs for all customers. The results of the tests conducted by the Utilities and their consultants have demonstrated that the programs will target certain customers and realize net benefits.

YECL stated that it concurs with UCG's view in argument that a reasonable approach to optimization of the DSM plan, while limiting ratepayer impact, is to examine the rate impact of programs and their results, and favour those programs with the lowest rate impacts and best results. YECL submitted that this is exactly what they have done. In optimizing the set of programs, ease of implementation of the program was considered to achieve early wins, to recognize that this is the first portfolio of DSM programs to be jointly delivered by the two utilities and to minimize program administration costs, thereby minimizing rate impact.

YECL concurred with UCG's argument that the Utilities need to show that the DSM programs being delivered are fair and valuable to all customers, participants and non-participants. YECL submitted that this has been clearly demonstrated through the results of the cost-effectiveness tests that have been applied. All programs pass the TRC, which shows that Yukon society achieves net benefits from the delivery of the programs; all programs pass the PCT, which means that there are net benefits to program participants; and all programs pass the PAC, which means that there are net benefits to the Utilities in delivering these programs. While not all program elements pass the RIM test, this is not an unexpected or unusual result for a DSM program. Not passing the RIM test means there will be a rate impact for non-participants without the offset from being a DSM participant.

YECL submitted that the impact to rates as a result of DSM costs is 0.1, 0.2 and 0.2 percent for 2013, 2014 and 2015 respectively. YECL contended that acceptable rate and bill impacts resulting from DSM programs are appropriate objectives of a DSM plan, and that the current DSM plan has met these objectives as the rate impact from the

DSM portfolio is small and not undue. In program delivery, YECL reiterated that the Utilities will be striving to maximize customer uptake for both residential and business customers in the programs within the DSM budget.

In response to UCG argument regarding the appropriate approach to determining the value of demand-side options, YECL submitted that there is no evidence to suggest that this is appropriate. Adding these costs to the TRC would expand the range of measures that would be considered cost-effective. However, for this first DSM portfolio, there was a broad selection of program elements that passed the TRC such that not all of these could be included in the DSM portfolio; an optimal set of program elements was chosen. As a result, there was no need to calculate a modified TRC or societal cost test.

In response to UCG argument that there is very little detail on the programs to be delivered, YECL submitted there was extensive information on the program portfolio contained in the CPR report, the three market characterization reports, the DSM program portfolio document, the program implementation plan, and the program evaluation, measurement and verification plan. Within the DSM portfolio plan, details have been provided on the modalities of the residential rebates in the DSM portfolio plan. It was standard practice for the DSM program administrator to have some flexibility in final program design to take account of any market or other changes that have taken place since the filing of the DSM plan to ensure that the program design is based on the best available information before the launch. Therefore, YECL submitted that it was important to have some flexibility in program details during delivery to make program adjustments to allow the program to evolve in response to customer uptake and changing market conditions.

Further, the Utilities reserved the right to revise eligible measures as needed in accordance with current market conditions, technology development, evaluation, measurement and verification results, and program implementation experience. These conditions, again, are standard practice. YECL added that the Utilities will seek to maintain these incentive levels as much as possible, but if adjustments are required, the programs will be tested for cost-effectiveness after the changes, and incentive levels will be balanced in order to achieve equivalent results at the program level.

YECL noted that the Utilities carried out a thorough barrier analysis to make sure that there are DSM program tactics to tackle these barriers to wise energy use, and the program theory clearly laid out for each of the program elements. YECL argued that the DSM program by its definition only addresses the customer side of the meter. Projects which increase the efficiency of generation and distribution of electricity are investigated as part of the Utilities' resource planning and are considered supply side management. The Utilities were directed in Board Orders 2009-02 and 2009-08 to focus on Demand Side Management, which focuses on the end user of electricity and is intended to affect customer behaviour through incentives or disincentives for electricity usage. Further, YECL submitted that the Utilities have also addressed supply side management including internal efficiencies as outlined in YCS-YECL-7-1 and do not consider supply side management to be part of the proposed DSM program.

In response to UCG concern in its argument regarding consultation, YECL submitted that a high-quality consultation process was conducted throughout the process of developing the DSM plan, as detailed in the responses to UCG-YECL-128(a) and UCG-YECL-128(b). These responses provided an extensive list of stakeholders who participated in the consultations and the associated presentation material. As shown, a wide variety of participants were engaged. Consultations began in January 2011 and continued through to June 2013, when the final program design was rolled out to the public. Further YECL submitted that there will be continued opportunities for stakeholder input through the evaluation, measurement and verification (EM&V) process that will be undertaken throughout the program delivery. Once the EM&V process evaluation report is completed midway through the program delivery, a stakeholder workshop will be organized and the stakeholder input will be used in the design of the next DSM program. Exhibit 8 of the PIP describes the Utilities' commitments to reporting parameters. The Utilities concur with UCG that the DSM annual report filing to the Board should contain the DSM expenditures, amounts of electricity saved, and the benefits realized on the system as a whole as well as a comparison to any specific program targets.

YECL further submitted that the actual costs incurred related to the DSM program will be subject to a prudency review at the time of its next GRA filing. Therefore, YECL submitted that UCG's recommendations regarding reporting should be rejected.

In response to the UCG argument that the developers of the DSM plan are not aware of the situation in Yukon in recent years, YECL submitted that the Yukon Energy Solutions Centre, Yukon Housing Corporation and the City of Whitehorse were all consulted in developing the plan, as evidenced in the CPR report, in the market characterization reports, and in the DSM program portfolio document. The DSM portfolio was designed to avoid overlaps with the programs already offered by these organizations and with the intent to complement the existing Yukon DSM initiatives in terms of technologies (conservation measures) and, or, in terms of market segments, as shown in the DSM program portfolio document.

YECL further stated that it has not forecast any costs related to internal DSM programs in the test period. Therefore, YECL submitted that UCG's recommendation is not relevant. YECL noted that it continues to make internal system efficiency improvements and to address opportunities to improve energy efficiency within its various facilities, as outlined in its response to YCS-YECL-7-1. Improvements include: conversions to higher voltages to reduce losses; designing substations to ensure impedances are optimized to reduce internal losses; insulation upgrades implemented in various plants; and building envelope improvements, air handling balancing and HVAC replacement in YECL’s facilities in Whitehorse. The benefits resulting from these efficiencies are incorporated into the forecast of costs for the test period and, as such, benefit ratepayers. As well, these improvements are outside of the scope of the DSM plan.

In reply argument, LE responded to some of the arguments put forth by UCG. More specifically, LE submitted that UCG had contended that the DSM program is more likely to just shift load than conserve energy; however, LE submitted that the programs UCG

cited are all energy-focused — i.e. they should save energy but they have no ability to shift load.

LE also submitted that UCG had contended that the DSM plan is a trial-and-error approach by the Utilities but in LE's view, the matter is just the opposite — that the Utilities have spent far more time and money studying DSM than they should have. LE argued that cost-effective programs could have been developed at far lower costs and in a shorter time frame.

LE reiterated its view that the DSM plan should be approved by the Board and that the Utilities need to get on with the program delivery immediately. LE also noted that YEC's LNG generation development proposal is proof of the need.

In reply argument, YCS disagreed with YECL's argument that time of use would merely move the peaks, not reduce them. YCS suspects that because the demand/capacity charge for General Service customers is an important and attractive revenue generator for YECL, it would not benefit from efforts to even out consumption over time. Shaving the peaks and filling the valleys would lower coincidental use of electricity — on which costly demand charges are based and calculated. While there may be some instances that YECL described when managing the load would result in the peak simply moving to a later hour — in extreme temperatures, for example — YCS submitted that because of the mixed hydro-diesel system, there would, in fact, be reductions in diesel peaking by managing the load.

YCS submitted that several DSM stakeholders and interveners have suggested time-of-use rates would be a valuable tool with which to do this. YCS hoped that the Board would recommend to the Utilities, as well as to the Yukon government, that an open-minded investigation into load management approaches that take advantage of a rate structure should be part of continued DSM planning.

UCG submitted that, YECL argued "that DSM-related savings after completion of the first year of the plan are 240 MWh and a cumulative 1,487 MWh after the completion of the second year of the plan. The Utilities' DSM plan expects savings of 9.3 GWh after the completion of the fifth year of the plan, valued at $1,953,000."[280] Notwithstanding the above, UCG submitted that these avoided new-generation savings do not even come close to the accumulated costs incurred by both utilities to this date and going forward on DSM-related activities. UCG submitted that the costs of new positions created for DSM by both companies have not been included in the analysis. UCG submitted that the Board must look at the total accumulated costs associated with the development and implementation of the DSM plan before approving any such costs associated with DSM.

As an example of the costs that have not been included in YECL's analysis, UCG referred to YEC's 2012-13 GRA within which YEC proposed that $3 million — net of contributions — of DSM expenditures be added to rate base on or before the end of 2013. YEC suggested at that time that over 90 percent of these expenditures were

[280] UCG Reply Argument, paragraph 98

related to DSM planning for which program cost-and-benefit assessments are not applicable, including the DSM Conservation Potential Review, pilot programs, community engagement, end-use surveys, working groups, energy audit and management plan, and public communication.

UCG submitted that the Utilities have not adequately addressed the issues of bill impacts, avoided costs and longer term aspects related to their proposed DSM programs to allow the Board to approve them as submitted. Ratepayers must be provided certainties as to who will pay for these costs, who will receive benefits from the DSM programs, and that facilitating marginalized customers will be addressed.

12.1 Views of the Board

As set out above, the Board, in its Reasons for Decision, Appendix A to Board Order 2009-02 and 2009-08, directed YECL and YEC to jointly consult with stakeholders and "develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA." However, the Utilities have taken this direction much further and developed and submitted a five-year program. The Board notes that the costs associated with the program development and implementation are high and include such items as In Charge branding, which YECL explained was:

> A. MS. CARLSON: … for the work that we've done with a local communications group to assist us in developing the brand of In Charge. This would be for developing a logo as well as brand values and rules of use within the brand, so that, as stated earlier, we would be rolling out a joint brand to deliver DSM programs rather than under the individual utility brand. [281]

The Board understands from the testimony from the DSM witnesses and the evidence filed, that the Utilities had begun incurring costs either in anticipation of the DSM plan being approved or implementation of the DSM program itself. An example of such costs relates to the line item titled "launch contractor," in the 2013 schedule that was submitted in response to YUB-YECL-24(b). YECL testified that it had engaged a contractor to assist the Utilities in starting up the program and to provide training to staff on the evaluation and verification processes of the DSM plan. The witness stated:

> Q. A. MS. CARLSON: So the intent is to engage a launch contractor with previous experience in starting up a demand side management program to come in and provide guidance, assistance and best practice information to the utilities as to how to best set up and deliver our programs.
>
> And this launch contractor will also provide some training to our staff, ensure that they understand how to collect the data appropriately to feed into our EM&V plans and how to best engage the customer.

The Board is of the view that many DSM-related expenditures already incurred by the Utilities test the limits of what would be expected of a policy paper. The Board further considers that the Utilities must have been aware that to proceed with any DSM

[281] November 7, 2013 transcript, page 778, lines 9-15

activities beyond the Board's direction could result in the incurred costs being disallowed if the DSM plan was rejected by the Board.

The Board recognizes that, with the exception of UCG, interveners generally are supportive of a DSM program in Yukon; however, when deciding whether to approve any program expenditures, the Board must carefully weigh the benefits arising from the program with the costs of implementing the program, and if, in the Board's view, the project is not in the best interest of ratepayers, the Board cannot approve the project even if it was supported by interveners.

In this situation, the Utilities have estimated the avoided costs of new generation resulting from the DSM plan at $1.95 million[282] by the end of the fifth year of the DSM plan and the total costs of implementing the DSM plan as proposed at approximately $6.9 million.[283,284] The Board notes, however, that if the lifetime electricity savings are taken into consideration, the avoided costs of new generation, based on $0.21 per KWh, would be approximately $20.8 million.[285] Although the estimates demonstrate that there is a substantial opportunity for cost savings over the lifetime of the DSM program, the Board has a number of reservations with respect to the DSM program and therefore, cannot approve the program in its entirety.

The Board is concerned that not all of the program elements pass the Rate Impact Measure (RIM). Although the Board recognizes and accepts that DSM programming will not benefit all ratepayers equally, the Board finds it undesirable that some program elements benefit some ratepayers — i.e. the participants and Utilities — at the expense of others — i.e. non-participants. The Board agrees with UCG's argument that low-income customers are more likely to be excluded from participating in the DSM program due to barriers and, as a result, harmed by DSM program elements that fail the RIM test. In the Board's view, all program elements must at least be rate-neutral for all ratepayers.

The Board does not agree that DSM programming should be extended to government buildings or the commercial sector at this time. The Board recognizes that DSM programming is in its infancy in Yukon and believes that the Utilities should focus their efforts on supporting the non-government residential DSM initiatives first. Further, the Board disagrees with interveners who have suggested that the DSM plan is not aggressive enough and that the Board should order the Utilities to introduce more program elements in the future. Before the Utilities consider other additional initiatives, the Board wants to see that the Utilities can deliver on the promised electricity and cost savings of the proposed program elements first.

Based on the overall positive potential of the DSM programming presented in this proceeding, the Board approves program elements of the residential non-government DSM portfolio that pass all of the four cost-effectiveness measures for 2014 and 2015.

[282] DSM Undertaking #8.
[283] DSM Undertaking #7.
[284] The $6.9 million figure is the sum of the forecast DSM costs from 2014 to 2018.
[285] Lifetime electricity savings derived using the methodology and cost of avoided generation used in DSM Undertaking #8.

More specifically, this includes the LED Lighting and Automotive Heater Timer Rebates and the Low-cost Energy Efficient Products program elements. Accordingly, the Board orders YECL in its compliance filing to provide a revised budget for DSM programming in 2014 and 2015 based on Board's findings and approval above. In addition, the Utilities had initially forecast DSM-related administrative and overhead costs, communication and engagement costs, and staffing costs, based on approval of the overall DSM plan proposal. Since the Board has ordered a substantial reduction in the scope of the DSM program, the Board orders the Utilities to reduce the amount of DSM-related administrative and overhead costs, communication and engagement costs, and staffing costs, on a pro-rata basis with the new DSM budget and to file these costs with the Board in the compliance filing. In its compliance filing, YECL is also to provide to the Board a schedule outlining the targets — i.e. key performance indicators — for the approved DSM program elements for each of 2014 and 2015.

In response to DSM Undertaking #7, which was to provide "what's already been spent and what is forecast to be spent by both utilities on all DSM-related activities to the end of 2018, subtracting out the cost related to the development of the plan or the policy paper," YECL submitted costs spent on DSM in 2011, 2012 and 2013 but not related to the "development of the plan or the policy paper." Since the Board has ordered a substantial reduction in the scope of the DSM program, the Board orders the Utilities to reduce the amount of these identified costs on a pro-rata basis with the new DSM budget and to file these costs with the Board in the compliance filing. The Board orders YECL to capitalize the amounts spent in 2011, 2012, and 2013 related to "development of the plan or policy paper" and the pro-rata amount of the costs already spent in 2011, 2012 and 2013 but not related to the "development of the plan or policy paper," and to amortize these costs over the 2014 to 2018 period.

As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the Utilities benefit, but if participation rates are higher than expected, the Utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the Utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA.

Further, the Board affirms it does not approve the program for the five-year term requested and that the Utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.

13 OTHER MATTERS

13.1 Deferral Accounts

YECL sought approval of several accounts, including one where YECL sought the ability to flow-through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that YECL operates under, or that bear on the nature and extent of YECL's obligations as a regulated utility and which impact its 2013-15 revenues or revenue requirement.

YECL submitted that this deferral account was requested to maintain consistency with a similar deferral that was approved as part of the 2011-2013 GRAs of each of Northland Utilities (Yellowknife) Ltd. and Northland Utilities (NWT) Ltd. In their respective decisions, the approved wording of the deferral account was:

> …a deferral account which would be used to record amounts associated with any Board decisions that result in changes to the rules or parameters that Northland operates under, including such areas as the billing system, collection practices or the frequency of meter reading, or statutory or legislative provisions or changes that bear on the nature and extent of Northland's regulated utility obligations or operations and which impact Northland's 2011-2013 Revenues and/or Revenue Requirements. For clarity, no such recorded amounts would be approved by the Board as part of this Negotiated Settlement. Rather, the balance(s) would be brought forward by Northland for consideration in Northland's next General Rate Application.[286]

CW submitted that YECL had not provided satisfactory evidence or reasons in support of its proposed deferral account. Noting that the above words were approved as part of negotiated settlements, CW further submitted that matters agreed to between a utility and interveners in the context of a negotiated settlement represent any number of gives and takes between negotiating parties, and accordingly, "do not form a precedent for the purposes of establishing the reasonableness of any one item in the settlement."[287] Noting the criteria for the establishment of a deferral account,[288] CW submitted that YECL had not provided any evidence to address the criteria with respect to the requested deferral account.

UCG submitted that YECL's proposed deferral account was an "end around involving the avoidance of the traditional risks borne by a regulated Company that are reflected in its capital structure."[289] Accordingly, UCG recommended that the Board reject YECL's deferral account related to Board Orders or legislative provisions.

YEC expressed its concern respecting YECL's proposed deferral account, submitting that there was no precedent in Yukon for the account and YECL provided few precedents from elsewhere to support the proposed deferral account. YEC also stated

[286] YECL Information Requests, YUB-YECL-3(b).
[287] CW Final Argument, paragraph 54.
[288] Costs are not under the control of the Company and are not reasonably forecastable, or an error in forecasting could produce a loss or gain of a substantial magnitude, YECL Application, pages 1-5 and 1-6.
[289] UCG Final Argument, paragraph 235.

that there was no clear rationale or justification for application of the deferral account in Yukon:

> The flow through of costs related to Board Orders or legislative provisions seems designed to address issues that have arisen in NWT but have not occurred to date in Yukon. However, maintaining consistency with sister utilities in NWT is not a sufficient rationale for deviating from past Yukon practice and introducing a new deferral account as ill defined and open ended as the above account proposed by YECL.[290]

In summary, YEC submitted that such an account is wholly unprecedented in Yukon and should be disallowed.

YECL submitted that changes to revenue requirement resulting from Board Orders or legislative changes could not be forecast and are not within YECL's control, and as such, meet the standard criteria for the establishment of a deferral account. Moreover, YECL stated that items could arise within a short period that would not allow YECL sufficient time to defer the cost implications to a future GRA.

> … given the three year test period being requested and Yukon Electrical's track record from 1996 to 2012 of managing to stay out for several years between test periods.[291]

YECL submitted that it has justified the need for this deferral account and that it should be approved as filed.

YEC explained that it was very concerned that the proposed deferral account was forcing utility regulation down a path that "re-juggles the traditional and long held apportionment of risk… (with limited opportunities to benefit from undertaking the risk) while shielding the utilities from many risks that traditionally are borne by them."[292] YEC submitted that nothing has changed materially in the regulatory environment to support the need for the new risk management mechanisms. Accordingly, YEC recommended that the Board should not approve the deferral account at this time.

13.1.1 Views of the Board

The Board notes that legislative and regulatory changes can have an impact on utilities. However, on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented. The Board notes the YECL submission that no costs have been incurred to date that YECL would be seeking to incur in this deferral account.[293] The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any subsequent GRA filing. Therefore, the Board rejects YECL's request for this deferral account.

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[290] YEC Final Argument, page 17.
[291] YECL Reply Argument, paragraph 75.
[292] YEC Reply Argument, page 10.
[293] November 4, 2013 transcript, page 139, lines 2 -4, YECL responded "Correct" to the question, "Okay. And no costs have been incurred to date that YECL would be seeking to incur in this deferral account".

13.2 Retroactive Ratemaking

UCG and WL submitted that, based on the timing of the filing of the Application by YECL — filed while the first test year had commenced but before that test year concluded — recovering the rates related to 2013 would be tantamount to retroactive rate-making.

UCG stated that[294]:

> Just because the Board has ruled on past applications brought by both YECL and YEC where rates were implemented on a full year basis even though the applications were filed after January 1 of the relevant test year in question, it should not be concluded that this can be considered normal industry practice from both the standpoint of the factual backdrop and the statutory requirements.

UCG cited examples in other jurisdictions — e.g. Alberta and Ontario — where decisions had been made concerning the prospective nature of the rate-making process. UCG submitted that "there should be no recovery of any foregone revenue from January 1, 2013 to the date on which the Board approves rates following the compliance filing related to this application"[295].

YECL argued that the timing of this GRA "is consistent with the timing of its previous GRAs as well as the timing of the filing by the Yukon Energy Corporation of its recent 2012-2013 GRA"[296]. YECL further stated that according to Section 29 of the *Public Utilities Act,* the Board is expressly permitted to approve a revenue requirement for a whole year in which a proceeding is initiated. YECL further added that by filing at the time it did, regulatory efficiency was achieved[297].

In reply, WL agreed with UCG on the retroactive rate-making issue and disagreed with YECL in terms of how the date of filing does not determine the length of the test period. WL was of the view that the test period length is at the discretion of YECL management. In addition, WL noted that if the GRA were filed prior to the test period, the need to review 2012 actual results would be lessened, and placeholders could have been used until the BCUC process was completed[298].

13.2.1 Views of the Board

The Board rejects the submissions of UCG and WL with respect to retroactive rate-making for the following reasons. Section 29 of the *Public Utilities Act* authorizes the approval of a revenue requirement for a whole year in which a proceeding is initiated. In this case, the Board had before it 2012 actual results available to test the 2013 and later test years which, in the view of the Board, results in regulatory efficiency because the Board has before it the latest and best information.

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[294] UCG Final Argument, paragraph 67.
[295] UCG Final Argument, paragraph 90.
[296] YECL Final Argument, paragraph 8.
[297] YECL Final Argument, paragraph 9, where YECL identifies efficiencies such as a 3-year test period, prepare forecasts based on 2012 actual results and the ability to incorporate the BCUC GCOC decision.
[298] WL Reply Argument, pages 5-6.

13.3 Inflammatory Comments

In its reply argument, YECL asserted that UCG had made submissions which were "replete with inflammatory and offensive commentary that has no place in this process"[299] and requested that the Board admonish UCG for such commentary.

13.3.1 Views of the Board

In relation to UCG's argument, the Board considers that inflammatory and accusatory submissions are unacceptable and unwarranted in this, or any, proceeding. Each party is entitled to make its case before the Board; no party should be the subject of invective or statements that are not based on the evidence.

14 PRIOR BOARD DIRECTIONS

Section 11 of the Application provides YECL's response to directions from Board Order 2009-02,[300] Appendix A. YECL provides responses to seven directions (Direction #2, 8, 19, 20, 23, 26, and 27).

14.1 Views of the Board

The Board has provided comments with respect to direction 23 from Board Order 2009-02 in the capital projects section of this Order. The Board is satisfied that YECL has complied with the other outstanding directions from Board Order 2009-02.

[299] YECL Reply Argument, paragraph 4
[300] Board Decision with reasons on YECL's 2008-09 GRA.

TAB 3

Yukon Utilities Board

Board Order 2017-01
Appendix A: Reasons for Decision
April 27, 2017

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1 Introduction

1. On May 11, 2016, pursuant to the *Public Utilities Act* and Order-in-Council 1995/90, the Yukon Electrical Company Limited (YECL or Applicant),[1] carrying on business as ATCO Electric Yukon (AEY), filed an application with the Yukon Utilities Board (Board) requesting an order approving forecast revenue requirements for the years 2016 and 2017 (test period) (Application). AEY is seeking approval of a revenue requirement of $53,890,000 for 2016 and $56,173,000 for 2017. The applied-for revenue requirement represents cumulative rate increases of 4.4 percent for 2016 and 7.5 percent for 2017, and year-over-year rate increases of 4.4 percent and 3.1 percent respectively.

2. Additionally, AEY sought approval of:

- an interim refundable rate rider of 11.62 percent, effective July 1, 2016;
- the continued use of currently approved deferral accounts, including purchase power flow-through, fuel price flow-through, and defined benefit pension costs during the test period; and
- new deferral accounts related to liquefied natural gas (LNG) fuel price changes, statutory tax rate changes, feasibility studies, and costs arising from Board Orders or legislative provisions not currently contemplated.

3. AEY is a private investor-owned utility serving more than 17,000 customers in 19 communities in the Yukon. AEY purchases power from Yukon Energy Corporation (YEC) for distribution to customers in Whitehorse, Marsh Lake, Tagish, Teslin, Haines Junction, Carmacks, Stewart Crossing, Pelly Crossing, Carcross, Keno, Ross River, Canyon Creek and a variety of rural areas surrounding Whitehorse. The company maintains backup generating plants in Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing in the event of a power interruption. AEY also owns and operates the Fish Lake Hydro plant which generates power, and generates and distributes power in Old Crow, Beaver Creek, Destruction Bay, Burwash Landing, Upper Liard, Watson Lake and Swift River.

4. On May 27, 2016, the Board issued Board Order 2016-01, in which the Board ordered AEY to publish a Notice of Application and Hearing for the General Rate Application (GRA) no later than June 3, 2016 in appropriate local news publications in AEY's service area to provide adequate notice to the public. AEY was also directed to make the Application and supporting materials available on its website: www.atcoelectricyukon.com, as well as in hardcopy upon request to AEY. Board Order 2016-01 set out a process schedule, pending ministerial approval, for the Application, with a hearing to commence on November 1, 2016.

5. On June 17, 2016, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to section 50 of the *Public Utilities Act*.

[1] Yukon Electrical Company Limited is the legal entity, and ATCO Electric Yukon is the brand name that is now used for the company's utility service operations in Yukon.

6. The Board, through Board Order 2016-02, issued June 24, 2016, granted intervener status for this proceeding to the following:

- City of Whitehorse (CW)
- John Maissan (JM)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Yukon Energy Corporation (YEC)

7. In Board Order 2016-02, the Board also approved a 9.41 percent interim, refundable rate adjustment rider, effective July 1, 2016. Subsequently, in Board Order 2016-02 Errata, the Board changed the interim rate adjustment rider to 11.62 percent, in order to account for a calculation error.

8. In its intervener registration letter, dated June 17, 2016, and subsequently, UCG indicated that it had contacted the Pacific Economics Group (PEG) to help UCG determine if it was possible to benchmark the costs and productivity of AEY. UCG requested that the Board issue a letter to PEG so it can be assured that it would have an opportunity to access recovery of its costs through the cost claims process set by the Board. UCG also indicated that the process schedule would need to be altered to allow for a series of interrogatories to determine if benchmarking was possible.

9. On June 21, 2016, the Board set out a process to address UCG's request. Submissions were received from AEY and UCG. On July 4, 2016, after consideration of the UCG request and parties' submissions, the Board, in Board Order 2016-03, denied the UCG request for a letter of comfort to PEG. No revision to the process schedule was required.

10. On August 12, 2016, UCG submitted a motion requesting that the Board issue an order requiring AEY to provide adequate responses to certain UCG Information Requests (IRs). The Board invited comments from AEY on the UCG motion and reply comments from UCG. In Board Order 2016-04, issued on September 2, 2016, the Board ruled on the UCG motion and directed AEY to provide further and better information responses by September 9, 2016. In that Board Order, the Board amended the process schedule to allow UCG to file its evidence after the receipt of the additional information responses.

11. The Board held an oral public hearing in Whitehorse, Yukon from November 1 to 3, 2016. The Board was comprised of Robert Laking, Chair, and members Andre Fortin, Meagan Hannam, Bonnie King and Phillip Fitzgerald.

12. At the hearing, the Board confirmed that Final Argument was due on November 24, 2016 and Reply Argument on December 15, 2016. The Board considers the record of the proceeding closed on December 15, 2016.

13. In reaching the determinations contained within this Board Order, the Board has considered all relevant materials of which the record of this proceeding is comprised, including the evidence and argument provided by each party. Accordingly, references in this Board Order to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be

taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 AEY Sales and Revenue

2.1 Overview

14. AEY stated that its sales and revenue forecast was based on a detailed analysis of historical sales data at the community level and takes into account the most recent data available at the time the forecast is prepared. This data consists of information gathered by AEY staff who work in the communities as well as information resulting from consultation with the City of Whitehorse, Yukon government officials and various local agencies and developers.

15. The following table summarizes AEY's energy sales forecast for 2016 and 2017 by customer class, along with the corresponding actuals for 2013 to 2014, and 2015:

Table 1. **AEY energy sales by customer class – 2013 to 2017 (MWh)**

Customer class	Actuals			Forecasts (Test Period)	
	2013	2014	2015	2016	2017
Residential	148,780	147,253	148,605	147,111	151,617
Commercial	159,322	154,709	155,346	152,187	153,336
Street Lights	3,719	3,765	3,886	3,944	4,008
Private Lights	551	544	519	492	472
Total Retail Primary	313,372	306,272	308,356	303,735	309,433
Secondary Sales	3,959	5,415	7,030	9,429	9,429
Wholesale Sales	356	495	430	427	427
Total	316,687	312,182	315,816	313,592	319,289

Source: Application, Table 1, page 2-1.

16. Due to the changes in the energy sales by customer class, AEY's total primary non-industrial sales are forecast to decrease by 1.5 percent in 2016, and increase by 1.9 percent in 2017.

17. AEY provided an update to its test-period sales forecast to include nine months of actuals to September 30, 2016, as shown in the following table:

Table 2. **AEY updated test period sales forecast by customer class (MWh)**

Customer Class	Forecasts (Test Period)	
	2016	2017
Residential	146,698	153,275
Commercial	153,635	154,639
Street lights	3,922	3,978
Private lights	496	480
Total retail primary	304,751	312,373

Secondary sales	9,429	9,429
Wholesale sales	427	427
Total	314,607*	322,229

Source: Exhibit B-20, AEY undertaking; *Corrected for addition.

2.2 Views of the Applicant

18. In 2015, AEY provided electricity services to approximately 17,600 non-lighting customers in its service area and supplied a total of 308.4 GWh to residential, commercial and lighting customers. This represents an increase in total primary sales of 0.7 percent from 2014 levels. This increase follows decreases of 2.0 and 0.6 percent respectively in 2014 and 2013, from prior year levels.

19. After experiencing strong growth in the Yukon from 2004 to 2012, AEY submitted that the pace of economic activity in the Yukon has slowed down significantly. Slower population growth has also contributed to minimal customer gains in the residential and commercial sectors of AEY. It expected that the overall impact of the economic and population growth slowdown to continue to impact AEY's customer growth and sales over the test period.

20. AEY added that its demand-side management (DSM) program and the Yukon government's energy initiatives, such as those related to the commercial energy incentive program and micro-generation, which were introduced in the Yukon over the last few years, have also contributed to lower electricity sales experienced in the period from 2013 to 2015.

21. AEY reviewed its two-step approach for determining weather-normalized use per customer (UPC), where:

> In the first step, the historical average monthly UPC is regressed on actual monthly Heating Degree Days (HDD), and in the second step, the coefficient of HDD from the regression in the first step is multiplied by the difference between the actual HDD and the "Normal" HDD.[2]

22. In its Application, AEY proposed to update the timeframes used to determine the weather-normalized UPC. The existing methodology uses a longer time period and the proposed methodology uses the last three years of data, as illustrated in the table below:

Table 3. **Comparison of weather-normalized UPC methodologies**

	Regression data for UPC (Step 1)	**"Normal" HDD (Step 2)**
Prior Methodology	15 years	20-year average
Current Methodology	3 years	3-year average

Source: Application, page 2-5.

[2] Exhibit BB-1, Application, page 2-5, lines 3-7.

23. In the proposed methodology, AEY would apply the growth rates experienced over the period from 2013 to 2015 to derive the forecast UPC for the test period.

24. In support of its proposal, AEY stated:

> … over the past few years, in addition to changes in electric heating, there has been an increase in energy efficiency programs in the Yukon such as Demand Side Management and the Commercial Energy Incentive program. These trends, combined with a decline in economic activity and increasing effects of global warming have contributed to an overall downward trend in UPC over the 2013-2015 time period.[3]

25. AEY submitted that using the 2013 to 2015 timeframe for weather-normalizing and forecasting the UPC was more appropriate, as it encompasses trends occurring in the Yukon over the last few years.

2.2.1 Residential sales forecast

26. Respecting its residential sales forecast, AEY stated that the forecast has two key inputs: net customer additions and the UPC. The energy sales forecast is obtained by multiplying the forecast number of customers, which includes all known residential property developments, by the weather-normalized UPC forecast.

27. AEY submitted that the residential average UPC for all communities (except for Keno City, Stewart Crossing and Swift River) is calculated by using the weather-normalized UPC of the previous year as a base and applying the 2013 to 2015 growth in weather-normalized UPC. For Keno City, Stewart Crossing and Swift River, AEY used the actual UPC of the previous year as a base[4] and applied the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC for these communities was "used because there are very few customers in these communities and there is poor correlation between their average UPC and temperature."[5] The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

2.2.2 Commercial sales forecast

28. Similar to the residential sales forecast, the commercial sales forecast has two key inputs: net customer additions and the forecast UPC. The energy sales forecast is determined by multiplying the forecast number of customers (based on the net customer additions forecast) by the UPC forecast.

29. AEY stated that Whitehorse's commercial UPC for the test period is forecast using the weather-normalized UPC of the previous year and applying the 2013 to 2015 growth in weather-normalized UPC. AEY added that it expects three new large commercial customers to be added during the test period in Whitehorse. AEY added:

[3] Exhibit BB-1, Application, page 2-5, lines 14-19.
[4] Exhibit B-9, YUB-YECL-7 (a): "For the purpose of forecasting the 2016 UPC, 2015 is considered to be the previous year. For the purpose of forecasting the 2017 UPC, 2016 is considered to be the previous year."
[5] Exhibit BB-1, Application, page 2-6, lines 11-12.

> ATCO Electric Yukon has considered these new large customers individually, and has forecast the load each customer will bring to the system each year based on the start-up time and other pertinent information provided by the customer. The commercial energy sales for Whitehorse are then calculated by adding the specific energy sales of the new large commercial additions to each of the test years.[6]

30. With the exception of Whitehorse, AEY submitted that the commercial UPC forecast for all communities is determined by using the actual UPC of the previous year, and applying the 2013 to 2015 growth in actual UPC. AEY explained that actual UPC is used because there are fewer commercial customers in these communities or there is poor correlation between their average UPC and temperature. The community energy sales forecast is then calculated by multiplying the forecast community customer counts by the respective community UPC forecast.

31. In response to UCG, AEY reiterated that three main factors have contributed to the declining trend in residential and commercial UPC, and these factors support the updated forecast methodology. These are:

(a) the economic slowdown in the Yukon;

(b) a continuous warming trend, starting in 2013; and

(c) recent energy conservation initiatives, which have been implemented in the Yukon.

32. AEY added that the proposed change from 15 years to three years to run its regression model for UPC and HDDs results in a more accurate portrayal of the current context in which AEY operates, and is necessary in order to appropriately account for the factors that have led to the change in UPC behaviour since 2012.[7]

33. During the oral hearing, AEY updated its sales forecasts to incorporate nine months of actuals, as of September 2016. The updated sales forecast provided in a table in response to the undertaking showed energy sales to be with 0.3 percent of actuals.[8]

2.2.3 Views of interveners

34. Mr. Maissan noted that residential and commercial sales are expected to decrease slightly in 2016 and then increase modestly in 2017. Mr. Maissan further noted the secondary sales were forecast to increase by 2.4 GWH in the test years. Mr. Maissan recommended that the Board accept AEY's sales forecast as filed.

35. UCG pointed out that AEY has consistently realized sales that were below the approved amounts. UCG submitted that this is in part due to AEY's forecasting methodology, as well as under-estimating the impact of weather, the economy and DSM initiatives. Given the downturn in the Yukon economy and the uncertainty created by a new territorial government, UCG submitted that AEY had erred in simply applying the

[6] Exhibit BB-1, Application, page 2-6 (lines 26 to 27) to page 2-7 (lines 1 to 3)
[7] YECL Final Argument, paragraph 24.
[8] Transcript, Volume 2, November 2, 2016, page 347, lines 1 to 4.

sales growth rates experienced over the 2013-2015 period to derive the weather-normalized UPC for the test period.[9]

36. UCG submitted that AEY should be directed to update its most recent sales forecast provided in its undertaking found at Exhibit B-2 with actuals from 2016 and 2017. This update should be provided when AEY submits its compliance filing and should use the most recent actuals and forecast to determine revenue requirements.

2.2.4 Views of the Board

37. The Board notes that AEY argued that the major reason for the shift in timeframe from 15 years to three years regarding its running of the regression model for UPC and HDDs was due to the shift and the change in direction respecting UPC starting in 2012.[10] AEY has affirmed the contributing factors as being the downturn in the economy and conservation initiatives.[11]

38. The Board finds that recent trends in the Yukon underpin AEY's proposed change in its methodology but the Board has concerns that a recent trend may or may not be reflective of future forecasts required in a test period. The Board considers it important that a methodology be adopted that is representative of energy sales and reflective of UPC and HDD in future years. The Board has concerns that if, for example, there is economic growth prior to the next GRA, a further adjustment to the methodology will be required due to a short time period being used to forecast energy sales.

39. With respect to its updated sales forecast, AEY's original forecast was within 0.3 percent compared to actuals for the 2016 test year. However, the Board notes that there is a one-percent variance in total retail primary sales for 2017 when the updated forecast is compared to the original forecast.

40. The Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016."[12] Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data.[13] Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast,

[9] UCG Final Argument, paragraph 76.
[10] Transcript, Volume 2, November 2, 2016, page 341 (line 24) to page 342 (line 2).
[11] Transcript, Volume 2, November 2, 2016, page 342, lines 4 to 22.
[12] AEY Final Argument, paragraph 26.
[13] Transcript, Volume 2, November 2, 2016, page 343, lines 17 to 20.

incorporating its prior methodology[14] using a 10-year timeframe for UPC regression and normalizing HDD.

3 Purchase power

41. AEY submitted that its primary and secondary purchase power costs are forecast to remain relatively flat over the test period. The following table shows the actual and forecast purchase power over the period from 2013 to 2017:

Table 4. **Actual and forecast purchase power – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	**2014**	**2015**	**2016**	**2017**
Primary Purchase Power	25,552	24,503	24,725	24,451	24,921
Secondary Purchase Power	292	415	454	415	415
Less: Capitalized[15]	(402)	-	(72)	(110)	(86)
Total Purchase Power[16]	25,442	24,918	25,107	24,756	25,250

Source: Exhibit BB-1, Application, page 3-1.

42. The purchase deferral account is related to increases or decreases to the cost of purchased power, which is based on YEC's rates for primary energy sales and secondary sales.

43. AEY submitted that the test period purchase power forecast takes into account the Fish Lake hydro generation output, which is based on the lifetime average output for Fish Lake Unit #2 from 1960-2015 plus the two-year average for the new Fish Lake Unit #1 adjusted for planned decreases in generation due to capital builds.[17] The drivers of the forecasts for 2016 and 2017 were stated as:

> The 2016 and 2017 capital that are causing short term reductions in generation are the replacement of Ditch 1 due to the spillway failure and the Fish Lake Ditch 3 Diversion Replacement in 2016. In 2017, water flows will be reduced for the Fish Lake #2 Head Pond Spillway Replacement and the Fish Lake Unit 1 Spillway Diversion Structure.[18]

44. Furthermore, consistent with the approach approved in Board Order 2014-06, AEY submitted that lines losses are calculated on a five-year average and total 6.2 percent.[19]

[14] The methodology used in its 2013-2015 GRA.
[15] Exhibit BB-1, Application, page 3-1, footnote 1: "Consistent with Board Order 2009-2, AEY will continue to capitalize the incremental purchased power costs for decreased hydro supply resulting from capital builds and rebuilds."
[16] Rider J has not been included, as these are flow-through amounts to YEC.
[17] Exhibit BB-1, Application, page 3-1 (lines 17-18) to 3-2 (lines 1-2).
[18] Exhibit B-9, YUB-YECL-9(a).
[19] AEY Final Argument, paragraph 31.

3.1 Views of interveners

45. UCG submitted that the incremental purchased power costs to be capitalized should only relate to planned capital projects and not maintenance or other projects that were not included in the capital budget reviewed by the Board.[20]

3.2 Applicant responses to interveners

46. In response to UCG's submission, AEY stated that its understanding of Board Order 2009-02 is consistent with UCG's on this matter.

3.3 Views of the Board

47. The Board's determination in Board Order 2009-02 respecting the capitalization of purchase power costs required because of the Fish Lake hydro was based on "YECL's Fish Lake generation forecasts as well as the expensing of purchase power costs associated with Fish Lake hydro rebuilds."[21] The Board directed AEY, at the time of its next GRA, to provide clear documentation of these incremental power purchases due to the Fish Lake hydro rebuilds.

48. In the current Application, AEY has capitalized the forecast purchased power costs related to the Fish Lake hydro rebuilds for 2016 and 2017. In the Board's view, this is consistent with directions provided in Board Order 2009-02:

> The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized. Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time. *(footnotes omitted)*[22]

49. The Board approves the forecast primary and secondary purchase power costs as filed because the methodology used is reasonable and consistent with the previous GRA.

3.4 Deferral Account — Purchase Power Flow-Through

50. AEY requested a Purchase Power Flow-Through Deferral Account (PPFTDA). AEY noted that the cost of purchase power in the Application is based on rates from YEC for primary energy and secondary sales and do not include any adjustments due to YEC's energy reconciliation adjustment (ERA). Any increases or decreases to the YEC rates or any ERA adjustments are to be flowed through to customers.

3.4.1 Views of interveners

51. UCG acknowledged that a deferral account is a reasonable way to track unforeseen changes in costs related to purchased power. However, UCG submitted that

[20] UCG Final Argument, paragraph 89.
[21] Board Order 2009-02, Appendix A, Reasons for Decision, page 9.
[22] Board Order 2009-02, Appendix A , Reasons for Decision, page 10

AEY must ensure that it limits as much as possible the charges from YEC by actively participating in reviews of YEC revenue requirements and implementing DSM initiatives that reduce the need for purchased power.[23]

3.4.2 Applicant responses to interveners

52. AEY responded to the UCG submission that AEY has participated in YEC regulatory applications that impact both AEY's customers and its share-owners and will continue to do so. AEY also submitted that it expects to continue working collaboratively with YEC on initiatives that impact Yukon electricity customers.[24]

3.4.3 Views of the Board

53. The Board notes AEY's responses to IRs on the PPFTDA. More specifically, the Board takes note of the response to YUB-YECL-47(b), in which AEY stated:

> … under a PPFTDA, AEY would assume risk associated with sales volumes, however AEY would not assume risk associated with changes to the Wholesale purchase rate... AEY submits that a PPFTDA is much more efficient than speculating on potential changes in its Wholesale costs resulting from changes to the Wholesale rate.[25]

54. Further, AEY stated that this account will ensure that there is an additional margin[26] if sales are greater than forecast.[27] Parties were asked to comment on that additional margin in argument[28], but no comments were received.

55. The Board accepts the submissions of AEY that the PPFTDA will provide additional margin on sales that are incremental to forecast levels and that the use of a PPFTDA is more efficient. The Board considers the PPFTDA to be a more efficient mechanism for adjusting potential changes in wholesale costs, especially since there are material timing differences between YEC and AEY GRA filings. Therefore, the Board approves the requested AEY PPFTDA, without changes.

4 Fuel costs

56. Fuel costs included in the AEY Application are reproduced in Table 5 below:

[23] UCG Final Argument, paragraph 88.
[24] AEY Reply Argument, paragraph 27.
[25] Exhibit B-9, YUB-YECL-47(b).
[26] By allowing the PPFTDA, a positive margin is maintained on incremental sales as incremental costs are covered through the deferral account.
[27] Transcript Vol. 3, page 520, lines 19-23.
[28] Transcript Vol 3., page 518, lines13-19.

Table 5. **Actual and forecast fuel costs — 2013 to 2015 ($000s)**

	Actuals			Forecasts (Test Period)	
	2013	**2014**	**2015**	**2016**	**2017**
Fuel Costs	6,708	6,760	6,621	5,225	5,268

Source: Exhibit BB-1, Application, page 4-1.

57. AEY explained that it purchases fuel on an ongoing basis for each of its five isolated plants via a diesel fuel tendering process, where a vendor is selected to be the provider of diesel fuel to AEY. AEY further explained that it has modest generation and fuel requirements associated with standby units that generate power in the event of an interruption of power on the Yukon interconnected system. The standby units are located at Carmacks, Teslin, Haines Junction, Ross River, Pelly Crossing and Stewart Crossing.

58. AEY stated that the forecast cost decrease in 2016 is mainly due to lower fuel prices than previously approved, which are currently used as the base fuel prices in Rider F. AEY added that the fuel costs forecast is a function of forecast sales, line losses, plant efficiencies and delivered prices. The fuel-deferral methodology used for this account was described, as follows:

> The previously approved methodology for the fuel deferral uses GRA-approved community-based plant efficiencies (or 'heat rate', kWh / Litre) and the plant's monthly gross generation to determine the quantum of litres for the monthly fuel deferral calculation. The difference between the actual and GRA-approved price per litre is then applied to this number of litres to arrive at the fuel deferral amount for the month.[29]

59. AEY submitted that the variance between actual and forecast fuel prices is refunded to or recovered from customers by means of Rider F, a fuel-price flow-through rider.

4.1 Views of the Board

60. The Board accepts and approves AEY's fuel cost forecast, as filed. AEY is proposing to continue the deferral for fuel prices for the test period.

4.2 Deferral Account — LNG Fuel

61. Notwithstanding the above, if the Watson Lake bi-fuel project is approved, AEY anticipated that, beginning in the fall of 2017, generation will be based on a variable fuel mix of diesel and LNG. Accordingly, AEY submitted that it required a deferral account to track and subsequently refund or recover changes in costs due to the differential in actual LNG fuel prices and the price included in rates. AEY explained that:

> Similarly to the Diesel Fuel Deferral Account, the LNG Fuel Deferral Account will use the GRA-approved community-based plant efficiencies and the plant's monthly gross generation to determine the volume of litres of diesel equivalent

[29] Exhibit BB-1, Application, page 4-2, lines 20-24.

> for the monthly fuel deferral calculation. Actual diesel volumes used for the diesel fuel deferral account calculation will be subtracted from this volume, with remaining allowable litres of diesel equivalent for use in the calculation of the LNG fuel deferral. [30]

62. AEY went on to explain that the difference between the actual and GRA-approved price per litre of diesel equivalent is then multiplied by the remaining allowable litres of diesel equivalent to arrive at the LNG fuel-deferral amount for the month.

63. AEY proposed to include the LNG price variances in the Rider F deferral account, stating that the principles supporting a diesel price variance deferral are the same as those supporting an LNG price variance deferral or a fuel price variance deferral, namely:

- Commodity prices are subject to material fluctuations outside the utilities' control; and
- It is not in ratepayers', the Board's, or the utilities' interests to speculate on these price fluctuations. [31]

64. AEY argued that it is well within the Board's authority to approve deferral accounts in general. Furthermore, should the Board determine that the wording of the Order in Council does not allow for the inclusion of LNG price variances in the existing Rider F, AEY submitted that a new deferral account and subsequent rider should be approved. Such a rider should operate in the same manner as Rider F.[32]

4.3 Views of interveners

65. UCG noted that Rider F was last approved in Board Order 2012-02, dated February 29, 2012. Noting that the Board, in Board Order 2011-15, confirmed that Rider F applies to all diesel fuel consumed in a period, UCG submitted that it is unclear whether AEY has applied to the Board for the inclusion of LNG price variances in Rider F.

66. Given that AEY is not using LNG at this time and only anticipates using LNG-fuelled generators late in 2017, at the earliest, UCG submitted that the Board should not allow AEY to establish a LNG-related deferral account until a need is established and an application has been made to change Rider F.

67. UCG further submitted that the Board cannot approve the proposed changes to Rider F for fuel used in Watson Lake without changes to section 8 of Order-in-Council 1995/90 to account for LNG use.

4.4 Applicant responses to interveners

68. AEY responded that section 8 of Order-in-Council 1995/90 provides for fuel-price adjustments and sets out that the Board must allow AEY and YEC to adjust their rates to retail customers, major industrial customers, and isolated industrial customers to

[30] Exhibit BB-1, Application, page 4-3, lines 7-12.
[31] Exhibit B-6, UCG-AEY-22
[32] Exhibit B-6, UCG-AEY-22

reflect fluctuations in the price for diesel fuel, without the requirement for specific application to and approval from the Board. However, simply because AEY is entitled to flow-through diesel fuel prices without Board approval, it does not mean that it is somehow prevented, upon Board approval, from flowing through the impact of changes to LNG prices.

4.5 Views of the Board

69. Considering the Board's determination in section 9.7.2 of this decision with respect to the Watson Lake bi-fuel project, the Board does not approve the LNG deferral account.

5 Operations and maintenance (O&M) expense

70. For 2016 and 2017, AEY requested approval of O&M expenses, totalling $11.993 million and $12.181 million respectively. The following table shows forecast and actual amounts for the period 2013-2015, and the forecast for the test years:

Table 6. **Operations and maintenance expense ($000)**

2013		2014		2015		2016	2017
Approved	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Forecast**	**Forecast**
11,604	11,718	11,882	11,698	11,944	11,616	11,993	12,181

Source: Exhibit BB-1, Application, Schedule 5.1

5.1 Labour

71. In the Application, AEY forecasted a complement of 70.38 full-time equivalents (FTEs) for each of the test years. This was an increase of 1.25 FTEs over the actual complement at the end of 2015.

72. AEY discussed labour costs in section 5 of the Application and stated that labour costs are calculated by multiplying the number of staff per job class by the rate of pay for each job class. The labour costs are then distributed to O&M accounts or capital accounts, depending on the nature of work being performed by the staff in the job class. Further, in section 1 of the Application, under the heading "Key Assumptions", AEY provided the following:

Table 7. **Key Assumptions**

	2016	2017
Labour inflation	3.25%	3.00%
Other inflation	2.20%	2.20%
Vacancy rate	4.00%	4.00%
Long-term debt rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 1-5.

5.1.1 Labour complement

73. AEY proposes a labour complement of 70.38 FTEs for each of the test years.

5.1.2 Views of interveners

74. Interveners did not provide any direct comments with regard to AEY's labour complement levels.

5.1.3 Views of the Board

75. Staff complement is one of the elements reviewed by the Board in relation to labour costs and the Board is concerned with the escalation of labour costs and the growth of Administration and General (A&G) costs. In this Application, AEY has requested an increase in its complement by two positions (an Engineering Technologist (1 FTE) and a Supervisor, Business Support Services (0.25 FTE)).

76. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change[33] in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY.[34] This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY.[35] Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement.

77. As of the close of record, the Engineering Technologist position has yet to be filled. AEY did not provide any evidence that the work forecast for the Engineering Technologist position was not already being done by any of the other two existing engineering technologist positions or other members of the two engineering groups.

78. In Board Order 2014-16, AEY was directed to remove the corporate accountant position (1 FTE). It did not do so and did not request a review and variance of that direction.[36] To continue the position or rename the position as an Operational Accountant ignores the direction and concerns of the Board.

79. Therefore, AEY's requested approval for a complement of 70.38 FTEs for both test years is not approved. The Board approves a complement of 68.13 FTEs. The

[33] Referring to the change from reporting to the Manager (Whitehorse-based) to the Business Support Services Supervisor (Yellowknife-based).
[34] Transcript Vol 2, page 365, lines 1-13.
[35] Exhibit B-9, YUB-YECL-34(a).
[36] Transcript Volume 2, page 372, lines 1-17.

complement level of 68.13 FTEs is determined by removing the Engineering Technologist position (1 FTE), the Supervisor, Business Support Services position (0.25 FTE), and the Corporate/Operational Accountant position (1 FTE) as directed in the 2013-2015 GRA. AEY is to reflect this finding in its compliance filing to this decision.

5.2 Vacancy rate

80. As noted above, AEY has forecasted a vacancy rate for each of the test years of 4.0 percent, or approximately three FTEs. AEY said that the vacancy rate is based on a five-year historical average and is consistent with the methodology approved in Board Orders 2009-02 and 2014-06.

5.2.1 Views of interveners

81. Interveners did not comment on AEY's proposed vacancy rates.

5.2.2 Views of the Board

82. The Board has reviewed the submissions of AEY on its vacancy rate in this proceeding. The Board finds the vacancy rate requested is reasonable because it is based on a five-year historical average and is consistent with the methodology approved in Board Order 2009-02 and applied in Board Order 2014-06.[37] For these reasons, the Board approves a vacancy rate for AEY of 4.0 percent for each of the test years.

5.3 Labour inflation

83. AEY stated that the labour escalation for 2016 was based on AEY's existing collective agreement which covers in-scope employees and AEY applied the escalators in that agreement to both in-scope and out-of-scope employees.

84. AEY reiterated its submission from the Application (section 5) that its inflationary increases were consistent with several decisions in Alberta.[38] It added that AEY was appropriately staffed and did not undergo the growth incurred by ATCO Electric prior to the economic downturn in Alberta; therefore, it was not impacted by the economic downturn in Alberta or the ATCO Group reorganization.[39]

5.3.1 Views of interveners

85. In argument, interveners did not make any specific comments on labour inflation. However, in Reply Argument, UCG stated "… it is inconsistent to have labour inflation rates from another jurisdiction dictate what Yukoner ratepayers should pay when Yukon-specific labour and wages information is readily available. UCG submits that AEY's labour inflation should be held to the most recent Yukon statistics available."[40]

[37] Appendix A to Board Order 2014-06, section 5.2.2, page 23.
[38] AEY noted the following decisions in its argument: 3539-D01-2015 (EPCOR Transmission 2015-2017 Tariff), 3577-D01-2016 (ATCO Pipelines 2015-2016 GTA), 20407-D01-2016 (EPCOR 2014 True-Up and 2016-2017 Forecast Capital Tracker) and 20555-D01-2016 (ATCO Electric Distribution 2014 True-Up and 2016-2017 Forecast Capital Tracker), at paragraph 66 of AEY's Final Argument.
[39] AEY Final Argument, paragraph 68.
[40] UCG Reply Argument, paragraph 20.

86. In addition, several of the interveners expressed concerns regarding AEY's costs. CW was concerned with AEY's pattern of over-forecasting.[41] John Maissan observed that AEY is able to control overall O&M costs.[42] UCG supported CW's concerns regarding over-forecasting, additionally mentioning "artificial inflation of rates".[43]

5.3.2 Views of the Board

87. The Board notes that, in the September 9, 2016 updated response to YUB-YECL-27(a), AEY stated that in 2015, 10 employees (15 percent of staff) did not receive wage increases, and in 2016, 11 employees (17 percent of staff) did not receive wage increases.

88. In response to Board questioning, AEY confirmed that the staff who did not receive wage increases in 2015 and 2016 were all out-of-scope employees.[44] Further, AEY stated that for the 2016 and 2017 test years, the labour inflation forecast was based on AEY's existing collective agreement, which expires on December 31, 2016. The labour-escalation rate for the test period is forecast to be 3.25 percent. AEY did not submit any information that a new collective agreement had been reached or would be in place for January 1, 2017. The Board considers that the 2017 forecast labour escalator is not based on a collective agreement that would be in force in 2017.

89. The Board notes that built into the determination of revenue requirement for 2015 was labour inflation of 3.5 percent. However, out-of-scope employees did not receive inflation increments for that year, nor for 2016. In-scope employees received 2015 and 2016 labour-inflation increments of 3.25 percent. For 2015, this was 0.25 percent lower than what was built into the 2015 revenue requirement.

90. As a result, for out-of-scope employees, the Board awards, for 2016, a labour-inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision.

91. For in-scope employees, the Board considered that a collective agreement was in place for the 2016 test period and approves the labour-inflation rate of 3.25 percent as requested for that year.

92. However, for 2017, since the Board has no evidence of the existence of a collective agreement, the Board has to determine the inflationary increase to be awarded for in-scope and out-of-scope employees. In making its determination, the Board considered the May 2016 *Yukon Economic Outlook.*[45] The Board notes that, based on the *Yukon Economic Outlook*, Yukon experienced an economic downturn in 2015 due to reasons such as:

- 2015 GDP was down by 3.8 percent;

[41] Exhibit C3-3, CW Evidence; CW Final Argument, paragraph 27.
[42] JM Final Argument, page 4.
[43] UCG Final Argument, paragraph 98.
[44] Transcript Volume 3, pages 400, line 16, to 401, line 8. .
[45] Exhibit B-9, YUB-YECL-30(a), Attachment 1.

- Average employment was down slightly;
- Unemployment rate was up 2.0 percent;
- Building permits were down 9.7 percent; and
- A modest decrease in the CPI for Whitehorse of 0.2 percent.

93. The preliminary forecast for 2017 discussed in the outlook is for Yukon's real GDP to fall by 5.7 percent, and employment and the labour force to be relatively flat. The Consumers Price Index (CPI) for Whitehorse is expected to be just under 2.0 percent.

94. For these reasons, the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction.

5.4 Pension matters

5.4.1 Defined Benefit Plan Contributions and Defined Benefit Pension Deferral Account

95. AEY provided the following placeholder amounts for pension costs in its Application:[46]

Table 8. **2013 to 2017 placeholder amounts for pension costs ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Defined Benefit	1,041	902	578	578	578
Defined Contribution	209	242	267	276	286
Total Pension Costs	1,250	1,144	845	854	864

Source: Exhibit BB-1, Application, page 5-3.

96. AEY sought Board approval for these amounts to be tied to the outcome of the upcoming ATCO Utilities Pension Application, to be filed before the Alberta Utilities Commission (AUC). In addition, AEY is seeking continuation of its pension deferral account to flow-through any increases or decreases to the defined benefit funding amounts as a result of any updated actuarial evaluations. For the defined contribution pension plan, AEY noted that the company's contributions rate was set at 6.0 percent.[47]

97. In an update[48] to defined benefit pension costs, AEY stated the costs for 2016 are forecasted to be $505,000, assuming a COLA of 100-percent CPI.

98. Further, AEY confirmed that if the deferral account is granted for pension costs, ratepayers would experience "actual cost" rather than placeholder amounts[49] and also

[46] Exhibit BB-1, Application, page 5-3.
[47] Exhibit BB-1, Application, page 5-3.
[48] Exhibit B-9, YUB-YECL-36(f).
[49] Exhibit B-5, JM-AEY-9.

confirmed that AEY would exclude any amounts the AUC does not approve for inclusion in utility rates in the Alberta 2016 pension application.[50]

99. In argument, AEY submitted that the assumption for 2016 of the COLA at 100 percent is based on changed circumstances, as the pension has moved from an unfunded liability to a funding-excess position.[51]

100. In its submission, UCG recommended that if the defined benefit pension deferral account was to be continued, its intended use should be clear, along with how it is to be used.[52] No other interveners made submissions on pension costs or this deferral account.

5.4.2 Views of the Board

101. The Board finds the requested pension amounts are reasonable. As a result, the Board approves the revised defined benefit pension amounts of $505,000 for each of the test years. The Board also approves the defined contribution rate of 6.0 percent, to be applied to the labour rates determined in section 5.3.1 of this decision.

102. Further, the Board approves AEY's request to continue with the Defined Benefit Pension Deferral Account (DBPDA). The Board finds that adjusting for the result of the ATCO Utilities 2016 Pension Application is a reasonable approach because it will reflect actual pension costs.

5.5 Other Inflation

103. As noted in the key assumptions,[53] AEY has requested other inflation of 2.20 percent for each of the test years. AEY stated that this forecast for the 2016 test year was based on the *Yukon Economic Outlook* dated October 2015. AEY added that since no public forecast was available for Yukon for 2017, it applied the 2016 forecast for that test year.

5.5.1 Views of interveners

104. Parties did not provide any specific comments on Other Inflation.

5.5.2 Views of the Board

105. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response.[54] In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent[55] for 2017. AEY is directed to reflect this change in its compliance filing to this decision.

[50] Exhibit B-4, CW-YECL-15(b).
[51] AEY Final Argument, paragraph 71.
[52] UCG Reply Argument, paragraph 21.
[53] Exhibit BB-1, Application, page 1-5.
[54] Exhibit B-9, YUB-YECL-30(a), Attachment 1.
[55] Exhibit B-9, YUB-YECL-30(b).

5.6 Non-labour costs

106. Non-labour costs were discussed in the Application. Schedule 5-1 provided a summary of actual and forecast costs. Schedule 5-2 provided year-over-year variance explanations.

107. AEY stated that non-labour costs are forecasted in two parts: (1) ongoing operational and administrative activities, and (2) new programs or projects. AEY added that it was not forecasting any new programs or projects for this test period.[56]

108. For ongoing operational and administrative activities, the forecast was based on historic spending and adjusted for known changes in work to be completed in the forecast period.

5.6.1 Views of interveners

109. CW submitted evidence challenging the forecast accuracy of AEY, stating:

> When the actual costs are systematically lower than forecast, one must question the reasonableness of the forecasts. When the approved forecast is continually higher than the actual costs for a cost category or item, it means customers are paying for costs the utility will not incur. While the utility is entitled to benefit from efficiency gains in the test period, the regulator must ensure that savings are from efficiency gains, and not the result of over forecasting. When there is a continual pattern of over-forecasting, that usually means that there is an issue with the forecast, and the subsequent forecast should be adjusted. Further, these savings should be captured in the subsequent rate application, to the benefit of customers.[57]

110. CW asserted that a pattern of over-forecasting for the production, distribution and general functions existed.[58] CW recommended that production costs be reduced by 15 percent[59] and that distribution and general costs be reduced by $272,000 in 2016 and $369,000 in 2017.[60]

111. UCG argued that "… there has been a pattern of over-forecasting and artificial inflation of rates in 2013-2015 with respect to O&M costs related to AEY's production facilities ($938,000) and overspending on administration and general ($458,000)."[61] UCG noted the variance between approved and actual affiliate charges for the 2013-2015 period. It recommended that affiliate charges should be reduced by 25 percent.

112. John Maissan submitted that AEY is able to control overall O&M costs according to their actual sales relative to approved forecast sales. He recommended that forecasted O&M costs for the 2016-2017 test years should be reduced by 1.1 percent.[62]

[56] Exhibit BB-1, Application, page 5-3.
[57] Exhibit C3-3, CW evidence, A5, pages 2-3.
[58] Exhibit C3-3, CW evidence, A6, pages 3-4.
[59] CW equated the 15-percent reduction in production costs to be $314,000 in 2016 and $306,000 in 2017.
[60] Exhibit C3-3, CW evidence, A7, pages 4-5.
[61] UCG Final Argument, paragraph 98.
[62] JM Final Argument, page 4, point 6.

113. In Reply Argument, UCG submitted:

> … that AEY has not provided the Board or interveners any alternative but to review O&M cost components. The only way to justify AEY's claim that O&M should only be reviewed in aggregate is if AEY has presented an integrated business strategic plan upon which its O&M is based.[63]

114. With respect to production costs, CW stated:

> … that in assessing the likely accuracy of any forecast in the application, the Board can and should take into account a pattern of over-forecasting in areas where that can be demonstrated.[64] (*underlining omitted*)

5.6.2 Views of the Applicant

115. In argument, AEY stated:

> Furthermore, the Bell Evidence does not take into account the oral testimony provided by Mr. Massie where he described a forecasting process that continuously informs the process with the best available information. Adjustment to the process are made based on historical costs and known costs looking forward. As noted by Mr. Massie, adjustments have been made to accounts going forward and these changes are reflected in the 2016-2017 test year forecasts.[65] (*footnotes omitted*)

116. AEY later added that it is more appropriate to look at total O&M costs and not isolate only those functions that are experiencing increases. In terms of $/MWh and O&M cost per customer, AEY argued that those metrics are influenced by the level of retail sales and those sales were actually decreasing by 1.5 percent. The forecasted average annual O&M cost per customer is flat with historical actuals.[66]

117. In reply to CW, AEY noted that CW did not provide any evidence as to why its method of forecasting is appropriate for the O&M categories in question. AEY went on further to say that CW failed to account for inflationary increases, based on the table provided in its argument that AEY has a history of accurately forecasting its O&M expenses.[67]

118. In reply to John Maissan's recommendation that O&M costs should be reduced by 1.1 percent, AEY said Mr. Maissan's recommendation ignored inflation as well as known increases in excess of inflation.[68]

119. In Reply Argument, AEY challenged UCG's request that affiliate charges be reduced by 25 percent. AEY stated that the difference between 2014-2015 actual amounts for affiliate charges related to the change in service provider and that change was fully reflected in the forecast for each of the test years.

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[63] UCG Reply Argument, paragraph 17.
[64] CW Reply Argument, paragraph 7.
[65] AEY Final Argument, paragraph 54.
[66] AEY Final Argument, paragraphs 58-59.
[67] AEY Reply Argument, paragraph 33.
[68] AEY Reply Argument, paragraph 35.

120. Regarding Administration and General O&M costs per customer, AEY countered the UCG argument by referring to corrected tables filed on November 10, 2016 to replace the original response to CW-YECL-13 Attachments 1 and 2. The update showed Administration and General O&M costs per customer to be less for the 2017 forecast than the 2015 actual.

121. AEY stated that its submissions for Financial Reporting and Regulatory Support affiliate costs should be seen as reasonable in comparison to 2013 amounts, especially given the regulatory events expected in 2017.[69]

5.6.3 Views of the Board

122. The Board is of the view, based on the evidence of CW, that AEY appears to have, at a high level, over-forecasted for each year in the 2013-2015 period. The Board views each year separately and not in aggregate. The forecast for each year is driven by different assumptions and different stages of planned programs. However, the Board agrees with AEY that the high-level approach submitted by CW can be overly simplistic. It is beneficial to have such a high level review, but the trend uncovered by that type of review should be the starting point for further investigation and not taken at face value. From an O&M perspective, deviations can occur due to changes in the capital/O&M mix. Deviations can also be related to deferring planned programs or increased work in other functions. Identifying a trend is insufficient. Identifying root causes and making recommendations for specific accounts or functions are necessary.

123. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual.

124. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period.[70] However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also

[69] The content of the preceding three paragraphs was derived from the AEY Reply Argument, paragraphs 36-41.
[70] Transcript Volume 3, page 444, lines 2-25.

directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs.

125. The Board will now discuss costs at the function level. Changes due to complement levels, vacancy rates, and inflation rates (labour and other) are discussed in earlier sections of this decision and those determinations impact production, distribution, public information and customer accounting function costs.

126. Other[71] costs, as provided in general function costs — in particular, Account 88800 (Maintenance for Company-Owned Houses), Account 88900 (Warehouse and Office Maintenance) — and administration and general function costs — particularly Account 72100 (Administrative) — are discussed in the following paragraphs.

127. **Account 88800 (Maintenance for Company-owned Houses).** "Other" costs were provided in AEY's response to City of Whitehorse's IRs. [72]Variance explanations were provided in Schedule 5.2 of the Application but only for Account 88900 and only for the change from the year 2013 to 2014. The following table shows the actual and forecast "Other" costs for this account:

Table 9. **Account 88800 — Maintenance, Company-Owned Houses — "Other" costs ($000s)**

Account 88800				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
18	27	41	54	51

Source: CW-YECL-14(a), Attachment 1, page 3.

128. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[73] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other" (Account 88800) is $47,000, and the 2017 balance for "Other" (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

[71] Other costs do not include the labour and fringe elements as provided in Attachment 1 of CW-YECL-14(a).
[72] CW-YECL-14(a), Attachment 1.
[73] Exhibit BB-1, Application, page 5-3.

129. **Account 88900 (Maintenance, Warehouse and Office)**. "Other" costs were provided in Attachment 1 to CW-YECL-14(a) and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the forecast and actual "Other" costs for this account:

Table 10. **Account 88900 — Maintenance, Warehouse and Office — "Other" costs ($000s)**

Account 88900				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
137	156	133	150	153

Source: CW-YECL-14(a), Attachment 1, page 3.

130. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period."[74] However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 "Other", (Account 88900) is $143,000, and the approved 2017 balance for "Other" (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision.

131. **Administrative and General function costs.** Schedule 5.2 provided explanations for the labour portions but did not explain the increase in "Other". Except for an explanation related to $21,000 for employee association agreement negotiations.

132. **Account 72100 (Administrative).** "Other" costs were provided in Attachment 1 to CW-YECL-14(a), and variance explanations were provided in Schedule 5.2 of the Application. The following table shows the actual and forecasted "Other" costs for this account:

Table 11. **Account 72100 Administrative — "Other" costs ($000s)**

Account 72100				
2013	**2014**	**2015**	**2016**	**2017**
Actual	Actual	Actual	Forecast	Forecast
1,481	1,541	1,256	1,556	1,585

[74] Application, page 5-3.

Source: CW-YECL-14(a), Attachment 1, page 3.

133. In YUB-YECL-45, AEY was asked to explain the increases in each of the "Admin and General" Accounts (Accounts 72100 through 72900). AEY provided explanations; for Account 72100, the explanation chiefly related to labour costs.

134. The three-year average (2013-2015) for "Other" for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in "Other" costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision.

6 Taxes Other Than Income

135. Taxes Other Than Income consist of property taxes paid to communities for AEY's office building, generation facilities, substation properties and power lines.

136. The following table summarizes AEY's recently approved, actual and forecasted amounts for property taxes:

Table 12. **Approved, actual and forecast property taxes 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	257	265	273		
Actual (A) / Forecast (F)	273	251	256	262	267
Actual (under) or over approved	16	(14)	(17)		

Source: Exhibit BB-1A, 2016-2017 GRA Schedule S1.1, line 10.

137. AEY stated that the increase in actual 2013 property taxes over the approved amount was due to payments made to the Town of Watson Lake.[75] Increases in property taxes that had been forecast for the years 2014 and 2015 did not occur because planned capital work, upon which property tax calculations are in part determined, did not materialize. Therefore, any year-over-year increases in property taxes paid during 2014 and 2015 were due primarily to inflation.

138. AEY has forecasted property taxes in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017.

139. AEY stated that property tax increases in the amounts of $0.006 million and $0.005 million for 2016 and 2017 respectively are due to inflationary increases applicable to each test year.

[75] Exhibit B-6, YECL Responses to UCG requests, UCG-AEY-28(b), PDF, page 150 of 260.

6.1 Views of interveners

140. In argument, UCG stated that AEY should not be allowed to increase property taxes for the test years due to a lack of evidence, such as the utility's property tax assessments.

6.2 Applicant responses to interveners

141. AEY replied that the position of UCG constituted new evidence that should be struck from the record or be given no weight by the Board.

6.3 Views of the Board

142. The Board considers that it is reasonable for AEY to forecast its 2016-2017 Taxes Other Than Income based on the application of relevant inflation rates by using, as a starting point, its 2015 actual property taxes paid. With respect to the issue of property tax assessments raised in Final Argument, the Board does not have sufficient information on the record of the current proceeding to determine that consideration of property tax assessments is required. If UCG wishes to explore the issue of whether property tax assessments should be provided in support of AEY's Application, it may bring forward this issue for examination in AEY's next GRA.

143. The Board approves AEY's "Taxes Other Than Income" amounts forecasted in the amount of $0.262 million for the year 2016 and $0.267 million for the year 2017, as filed.

7 Depreciation

144. In its Application, AEY forecasted depreciation expense in the amount of $5.792 million for the year 2016 and $6.283 million for the year 2017. This resulted in an increase from 2015 actual expense in the amount of $0.380 million in 2016 and $0.491 million in 2017. AEY explained that the increases were the result of forecasted growth in property, plant and equipment and subject to depreciation expense.

145. AEY stated that the depreciation rates used in the calculations of 2016 and 2017 depreciation expense were developed by way of a technical update, which relied on the depreciation parameters approved by the Board in Board Order 2014-06 for AEY's 2013-2015 GRA. In that application, AEY submitted a full depreciation study in support of the depreciation parameters ultimately approved by the Board. AEY also stated that in 2016 and 2017, it would continue to record the annual amortization of the accumulated depreciation reserve differences credit in the amount of $0.402 million,[76] [77] which was at the same level approved in Board Order 2014-06.

146. The following table summarizes AEY's recently approved, actual and forecast amounts for depreciation expense:

[76] This would have the effect of reducing YECL annual depreciation expense by $0.402 million.
[77] YECL 2016-2017 GRA Schedules, Schedule S7.4, line 50.

Table 13. **Approved, actual and forecast depreciation expense — 2013 to 2017 ($000s)**

	2013	2014	2015	2016 (F)	2017 (F)
Approved	4.520	5.252	5.778		
Actual (A)/Forecast (F)	4.382	4.895	5.412	5.792	6.283
Actual (under) or over approved	(0.138)	(0.357)	(0.366)		

Source: Exhibit 2016-2017 GRA Schedule S1.1, line 11.

147. During the course of this proceeding, three issues were raised with respect to depreciation, each of which is discussed in the sections that follow.

7.1 Technical update to determine updated depreciation rates

7.1.1 Views of interveners

148. There were concerns raised by UCG that AEY had not indicated nor requested approval in its application of the revised depreciation rates used in its calculation of depreciation expense for the test years stemming from the results of a technical update to its previous depreciation study.

149. UCG argued that since actual depreciation expense incurred for the 2013-15 test period had been lower than the amount approved to be recovered through AEY's tariff, this was evidence of an over-recovery of depreciation expense in the amount of $1.1 million[78] over the 2013-15 period.

150. UCG submitted that AEY's request for increases to its depreciation expense should be denied because of these two issues.

7.1.2 Views of the Board

151. The Board observes that there appears to be some confusion by parties pertaining to certain depreciation-related elements. The Board has provided the following general information with respect to the differences between a full depreciation study and a technical update to a depreciation study.

152. Depreciation expense typically encompasses three components of capital cost recovery: (1) the depreciation related to the original cost of the asset; (2) estimations related to net salvage costs (also referred to in this proceeding as future removal and site restoration); and (3) in some circumstances, the amortization of accumulated reserve differences that arise, in part, from changes in depreciation methodologies or depreciation parameters determined during the course of a depreciation study.

153. Periodically, a new depreciation study is conducted and three depreciation "parameters" — consisting of the average service life, the standard "Iowa curve" and dispersion pattern (collectively referred to as the life-curve parameters) and the net salvage percent parameter — are confirmed or revised. The actual accumulated depreciation recorded to date, based on the prior approved depreciation parameters,

[78] UCG Final Argument, PDF page 21 of 40.

can differ from the theoretical amount of accumulated depreciation that would have been recorded for each account using the updated parameters. The resulting difference — termed the accumulated reserve difference or variance — is measured in dollars and may be recovered or refunded through depreciation expense as a stand-alone true-up amount, or may be combined into a depreciation rate that includes the amortization of the accumulated reserve differences true-up amount.

154. During the preparation of full depreciation studies, technical updates are often conducted. The purpose of a technical update (which is less costly to prepare than a depreciation study) is to apply the currently approved depreciation parameters to the recent actual plant balance information provided by the utility in order to develop the most current and relevant depreciation rates for the test years. The most recent plant balances will reflect both plant additions and retirements occurring since the time of the last depreciation study or technical update.

155. To summarize, it is during the course of examining a depreciation study that the depreciation parameters of life-curve, net salvage percentages and the amortization of accumulated reserve differences are approved. The rates that are proposed by the utility are used as an input in depreciation expense calculations and are a direct result of the depreciation parameters being applied to the most recent actual plant-in-service information. During the course of a technical update, approved depreciation parameters are similarly applied to the most recent plant balances for the purposes of updating depreciation rates, which will then be used in depreciation expense calculations.

156. In its 2016-17 GRA, AEY submitted a technical update to its December 31, 2011 depreciation study, which had been submitted as part of the record in the 2013-15 GRA.

157. The technical update undertaken by AEY relied on currently approved life-curve depreciation parameters to determine updated depreciation rates for the 2016 and 2017 test years based on December 31, 2015 plant-in-service balances. The result was a total decrease in depreciation expense of approximately $0.100 million over the test years.[79]

158. In the case of AEY, and consistent with past Board Orders, there is no estimation made for recovery of any future net salvage costs. As a result, there is no depreciation parameter related to or reflective of a net salvage percent that would otherwise form a part of AEY's depreciation rates and therefore depreciation expense.

159. Furthermore, AEY has historically recovered any amortization of accumulated reserve differences as a dollar amount, which is generally determined and approved during the course of examining a depreciation study.

160. With respect to the 2016-17 amortization of accumulated reserve differences amount, AEY stated that it had "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[80] The

[79] Transcript, Volume 1 page 148.
[80] Transcript, Volume 3, page 424.

result was a credit, or refund, of depreciation expense in the amount of $0.402 million per year.

161. Based on the foregoing, the Board is not convinced by the concerns raised by UCG that there is a need to deny or adjust AEY's depreciation expense calculations due to its December 31, 2015 technical update. Consistent with common depreciation practice, AEY's technical update relied on currently approved life-curve depreciation parameters applied to its most recent plant balances for the purposes of updating its depreciation rates, which were used to inform its 2016-17 depreciation expense calculations. The Board finds there is not an issue with the derivation of AEY's forecast depreciation expense.

162. With respect to UCG's assertion of over-collection of depreciation expense for the years 2013-15, the Board determines the revenue requirement on a prospective basis. Depreciation parameters and the resultant rates are estimates applied to forecasted plant balances to determine forecasted depreciation expense. While the depreciation rates themselves will remain static during the test years, actual plant balances — upon which those rates are applied — may differ from those forecasted by the utility. The end result, as observed by UCG, may be differences between approved and actual depreciation expense.

163. For the purpose of calculating AEY's depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense.

7.2 Use of the mid-year convention for calculation of depreciation expense

164. During the oral hearing, Board counsel questioned AEY as to why, in its depreciation expense calculation for Account 493 — Demand Side Management, the mid-year convention had not been applied. The question posed was directed toward a common regulatory convention related to depreciation expense calculations whereby only a half-year of depreciation expense is taken in the year in which an asset has been capitalized into rate base, followed by full-year depreciation expense calculations in subsequent years. This mid-year convention supports that in the absence of having to consider individual and exact dates of capitalization for any given asset, an assumption can be made for depreciation purposes that, on average, all assets are capitalized at the mid-point of the year.

165. An examination of AEY's schedules indicated that depreciation expense had not been taken for any of the amounts on Account 493 — Demand Side Management 2016 capital addition. The amounts had been deferred to the year 2017 where a full year depreciation expense was recorded.

166. AEY witness, James Grattan, advised that if the Board determined that coincident with the capitalization of the asset in 2016 it should attract a half-year of depreciation expense in that same year, he would not be opposed to this calculation.[81]

7.2.1 Views of the Board

167. The Board considers that consistent with AEY's depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

168. For clarity, the Board confirms AEY's use of a five-year amortization period is acceptable for this depreciation expense calculation, in accordance with the findings in Board Order 2014-06.[82]

7.3 Supporting documentation for the amortization of accumulated depreciation reserve differences

169. During the IR process, AEY confirmed that costs related to net salvage had not been included in the depreciation expense for the years 2013-2017.[83]

170. AEY also confirmed during the oral hearing that despite its Schedule 7.4 — Schedule of Amortization of Differences identified for each account number, negative net salvage in varying percentages, the schedule did not include any costs related to the recovery of net salvage. James Grattan, witness for AEY, stated that Schedule 7.4 "… simply continued with what the Board approved as part of the 2013-'15 General Rate Application for amortization of differences…"[84]

7.3.1 Views of the Board

171. The Board is satisfied that the 2016-2017 depreciation expense calculated by AEY, including the calculation related to its amortization of accumulated depreciation reserve differences, does not include any amounts related to the recovery of net salvage.

172. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders.

[81] Transcript, Volume 3, page 427.
[82] Board Order 2014-06, Appendix A, page 101..
[83] Exhibit B-6, UCG-AEY-29(a).
[84] Transcript, Volume 3, page 424.

8 Return on rate base

173. AEY included the following information on return on rate base:

Table 14. **Return on rate base — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Return on Rate Base	5,550	5,782	5,838	6,945	7,400

Source: Exhibit BB-1, Application, page 8-1.

AEY explained that the growth in rate base is a result of capital additions and an increase in the return on equity (ROE). This resulted in the increase in return on rate base for the forecast period.

8.1 Cost of capital

174. AEY has requested the Board use the British Columbia Utilities Board (BCUC) Generic Cost of Capital (GCOC) proceeding as the benchmark for determining ROE. In addition, AEY is seeking a 60-basis-point risk premium over the BCUC GCOC benchmark to determine its ROE for each of the test years.

8.1.1 Rate of return on capital

175. In response to YUB-YECL-50, AEY cited the BCUC's most recent GCOC decision (G-75-13) but did not provide that decision as requested. In that decision, the benchmark rate was determined to be 8.75 percent.

176. AEY, YEC[85] and John Maissan[86] accepted the BCUC rate. CW did not comment on the rate established by the BCUC. UCG recommended that the Board use the most recent GCOC decision from the AUC.[87]

177. UCG added that given AEY's direct tie to the Alberta market, AEY should not be allowed to link its ROE for the 2016-2017 test period to the recently approved BCUC GCOC benchmark rate of 8.75 percent plus a risk premium of 0.60 percent.

178. YEC disagreed with the UCG position and stated:

> The Board has previously determined that the BCUC model is the precedent for Yukon; as such, in Yukon Energy's view there is no basis for using a different benchmark ROE for the current review.[88]

8.1.2 Applicant responses to interveners

179. AEY submitted that UCG has ignored past decisions of the Board and the clear statements of the Board as they relate to equity ratio and ROE in Board Order 2014-06.

[85] YEC Final Argument, page 3.
[86] JM Final Argument, page 6.
[87] UCG Final Argument, paragraphs 137-150.
[88] YEC Reply Argument, pages 3-4.

8.1.3 Views of the Board

180. In Board Order 2009-02, the Board ruled that the BCUC generic cost of capital (GCOC) model is the most appropriate and is generally accepted by parties.[89]

181. The Board, in Board Order 2009-08 stated:

> The Board continues to be of the view that relying on a generic ROE from a different jurisdiction is the most efficient means of addressing an inherently complex and costly matter. The Board strongly believes that such an approach is the most efficient manner for a jurisdiction such as Yukon.
>
> The Board considers that the BCUC approach has been successfully applied to both utilities under this Board's jurisdiction and has resulted in fair returns to both utilities.
>
> Therefore it is determined that the BCUC approach is a precedent for this jurisdiction and will continue to be the precedent for this jurisdiction until otherwise ordered by this Board.[90]

182. The Board continues to be of the view that the BCUC GCOC model is the most appropriate for Yukon for the reasons set out above. The Board does not agree with the submissions of UCG on this issue as no evidence was filed to persuade the Board to change its approach. Accordingly, the Board finds that AEY is to use the BCUC GCOC benchmark for ROE of 8.75 percent.

8.1.4 Equity premium

183. AEY engaged Concentric Energy Advisors, Inc. (Concentric) to determine whether a risk premium relative to the BCUC GCOC benchmark utility would be appropriate and, if so, what that risk premium should be. The report prepared by Concentric was submitted as Attachment 8.1 to the Application.[91]

184. AEY submitted that it faces greater business risk than the average Canadian or British Columbia benchmark utility and therefore warrants a risk premium. Concentric submitted that the premium should be 60 basis points.[92]

185. Concentric, based on its research, recommended a risk premium of between 40 and 75 basis points in comparison to the BCUC benchmark utility. The range was framed by FortisBC Electric at a 40-basis-point premium and PNG-West (Pacific Northern Gas-West), representing the upper boundary. Concentric chose 60 basis points, as it matched the 9.35-percent ROE awarded to Maritime Electric, a utility Concentric submitted had similar business risk as AEY but had a deemed equity ratio of 40.9 percent.[93]

[89] Board Order 2009-02 Appendix A: Reasons for Decision, page 29.
[90] Board Order 2009-08, paragraphs 280-282.
[91] Exhibit BB-1, Application, page 8-3.
[92] Exhibit BB-1, Application, page 8-4.
[93] Exhibit BB-1, Application, Attachment 8.1, page 6.

186. Concentric added:

> In most respects, the business risk of AEY has not materially changed since 2009 when the Board determined that a risk premium of 46 basis points above the benchmark utility in British Columbia was reasonable. Weak economic conditions in the province, coupled with the impact of energy efficiency and DSM programs, and increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales;
>
> The business risk profile of AEY is most similar to that of Maritime Electric, which derives a higher percentage of its electricity supply from company owned generation than AEY, but which serves five times more retail customers. Maritime Electric has an authorized ROE of 9.35 percent on 40.9 percent common equity;
>
> The business risk profile of AEY is also similar in many respects to that of Newfoundland Power, except that AEY is substantially smaller in terms of both customers served and rate base. Newfoundland Power has an ROE of 8.80 percent on 45 percent common equity; and
>
> The business risk of AEY is lower than that of PNG-West, which is similar in size but faces more risk than AEY due to the loss of a major customer that caused throughput to decline by 87 percent from 2003-2012. PNG West has an authorized ROE of 9.50 percent (or 75 basis points above the BC benchmark) on 46.5 percent common equity.[94]

187. AEY submitted that the business risks it faces encompass market demand, operational risks, small size and geographic environment and that these risks expose it to a higher degree of business risk compared to the BCUC benchmark utility as well as most utilities located in other areas of Canada.[95]

8.1.4.1 Views of interveners

188. YEC took the position that it is appropriate to use the BCUC benchmark ROE of 8.75 percent as the foundation, and that for Yukon utilities, it is appropriate to "apply a risk premium adder above the benchmark in order to reflect additional risks faced by northern utilities on an isolated grid."[96] However, YEC said that AEY's proposal deviates from the BCUC approach and from past Yukon precedent. AEY's approach maintains a requirement for expert evidence and testimony to determine ROE for Yukon utilities that potentially increases both the cost and complexity of these proceedings.

189. YEC recommended that the Board use the same methodology and justification for determining ROE that was established in the 2005 GRA — that is, a point midway between YEC and FortisBC Electric of 48.5 basis points.[97]

[94] Exhibit BB-1, Application, Attachment 8.1, page 32.
[95] Exhibit BB-1, Application, page 8-3.
[96] YEC Final Argument, page 3.
[97] YEC Final Argument, page 5.

190. In Reply Argument, YEC stated:

> BCUC decisions referenced in the current Board proceedings have confirmed the requirement for a risk premium relative to the approved benchmark for various BC utilities to reflect the relative size of the utility and the characteristics of its service area.[98]

191. YEC later added that in Board Order 2009-02, the Board stated:

> … that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.[99]

192. YEC then stated that the bookends for assessing a risk premium against the BCUC benchmark are FortisBC Electric and PNG-West.[100]

193. John Maissan argued that the position that AEY faces increased sales forecast risk due to customers switching home heating sources is speculative. Based on the conclusion of Concentric, the sales forecast risk does not have a material effect on the risk profile for AEY.[101]

194. Mr. Maissan noted that the concern regarding variation in earnings did not appear to hold. He referred to YUB-YECL-63(b), arguing that in spite of significant economic variations and sales variabilities in 2014 and 2015, AEY, with the exception of 2015, has consistently earned above approved ROE levels.[102]

195. Mr. Maissan recommended:

> … that AEY has flexibility in the way it manages its costs such that it fairly consistently over-earns its approved ROE, and therefor [sic] is not subject to nearly as much risk as it tries to make out it is. In my view a fair ROE is the BCUC Benchmark of 8.75% and any risk premium is more that adequately covered by its equity thickness of 40% as compared to BCUC's 38.5%.[103]

196. CW noted that Concentric concluded that, "In most respects, the business risk of AEY has not materially changed since 2009…"[104] CW submitted that the request for a risk premium was unwarranted.[105]

197. UCG argued that the appropriate benchmark should be based on the latest AUC GCOC proceeding and therefore did not make any recommendation with respect to an equity premium.[106]

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[98] YEC Reply Argument, page 4.
[99] Board Order 2009-02, Appendix A: Reasons for Decision, page 29.
[100] YEC Reply Argument, page 5.
[101] JM Final Argument, page 5.
[102] JM Final Argument, page 6.
[103] JM Final Argument, page 6.
[104] Exhibit BB-1, Application, Attachment 8.1 (Concentric Report), page 31. Concentric did subsequently state that "the most important change has been uncertainty; and unpredictability associated with usage per customer, especially among the residential class".
[105] CW Final Argument, paragraph 26.
[106] UCG Final Argument, paragraphs 137-150.

8.1.4.2 Applicant responses to interveners

198. AEY challenged CW's interpretation that the Board, in Board Order 2014-06, ruled that a risk premium was not necessary or that there was no incremental business risk. Rather, AEY submitted that the Board ruled that the determination of whether a risk premium should be applied was not clear, and the Board directed AEY to provide justification in its next GRA.[107]

199. AEY contended that Mr. Maissan's position that the Board only use the BCUC benchmark ignores the evidence that FortisBC Energy has lower business risk than AEY.[108]

200. In response to YEC argument, AEY said the approach it took was in response to a direction from Board Order 2014-06. Further, AEY disagreed with the submission of YEC that AEY's business risks have not changed, noting that AEY's usage per customer has made it more difficult to accurately forecast sales.[109]

201. For risk due to small size, Concentric stated:

> Given the extremely small size of AEY, Concentric considers that to be the most important risk factor for purposes of establishing an appropriate risk premium for AEY. In order to select a comparator group that was reasonably risk comparable, Concentric thought it was important to select smaller investor owned electric and gas distribution companies. Other regulators have accepted the importance of small size in setting the risk premium for regulated utilities. For example, the BCUC's Stage 2 Generic Cost of Capital decision states that small size relative to the benchmark utility was a factor in awarding FortisBC Electric a risk premium of 40 basis points (at page iv), that FortisBC Whistler was awarded an additional 25 basis points (for a total of 75 basis points above the benchmark) "in recognition of risks related to its small size" (at page iii), and that PNG-Tumbler Ridge was awarded an additional 25 basis points above the 50 basis point risk premium given to PNG-West due to "greater weight on factors related to size" among other things (at page iv).[110]

8.1.4.3 Views of the Board

202. The Board made its determinations with respect to an ROE risk premium in Board Order 2009-02 and 2009-08 as follows:

> *Should a risk premium be applied?*
>
> In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation.

[107] AEY Reply Argument, paragraphs 57-63.
[108] AEY Reply Argument, paragraphs 64-66.
[109] AEY Reply Argument paragraphs 77 and 80.
[110] Exhibit B-9, YUB-YECL-62(a).

> The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.
>
> *What risk premium should be applied to YECL?*
>
> In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.[111] *(footnotes omitted)*

203. The Board continues to maintain this view. For this Application, as in past GRA decisions, the Board does not have a recent YEC decision to determine one of the bookends for the risk premium range and to use to calculate an ROE premium as it did for Board Order 2009-02.

204. The Board notes that Concentric concluded that AEY's business risks have not materially changed since 2009.[112] Further, Concentric stated that weak economic conditions in Yukon, coupled with the impact of energy efficiency and DSM programs, as well as increased variability in residential usage per customer due to fuel switching, have made it more difficult for AEY to accurately forecast sales.

205. However, although forecasting sales volume may be more difficult, the table in the preamble to YUB-YECL-52 shows that AEY's actual sales — with the exception of one major growth year (2012) — are consistently within two percent of the previous year's levels. Further, Concentric concluded that sales forecast risk due to changing heating fuel sources does not have a material effect on the risk profile of AEY.[113]

206. Additionally, AEY testified:

> That we, as a utility, should be able to do come up with a forecast that's somewhat accurate to what our actual sales are going to be. It's changing and there's lot of challenges. You've got weather. You've got all the new demand side management programs, including micro-grid generation. There's lots to it. But I think it should be something that is expected that we should be able to take a guess at. Better than a guess. We should be able to do a thorough analysis and come up with a reliable forecast...[114] I would just add that we did know the existence or lack of existence of a weather-normalization account for ATCO Electric, but we didn't frame it as an adder to the risk premium per se.[115]

[111] Appendix A to Board Order 2009-02: Reasons for Decision, page 29 of 49.
[112] Exhibit BB-1, Application, Attachment 8.1, page 29.
[113] Exhibit BB-1, Application, Attachment 8.1, page 27.
[114] Transcript Volume 1, page 86, lines 2-13.
[115] Transcript Volume 1, page 87, lines 9-12.

207. Based on AEY testimony, sales volume risk is a risk AEY can manage and, in the Board's view, it is a risk that does not attract a risk premium. However, through the submissions of YEC and AEY and the comparisons with FortisBC Energy (the BCUC benchmark utility), the Board is persuaded that AEY can be eligible for a risk premium relative to the BCUC benchmark utility to mitigate risks other than those related to sales volume. The following paragraphs discuss the Board's determination of the appropriate level of the risk premium.

208. The Concentric report made the following comparisons:

> The 2016 Generic Cost of Capital proceeding is currently underway in British Columbia and a decision is expected by July 2016. The benchmark utility, FortisBC Energy, has lower business risk than AEY. FortisBC Energy is substantially larger than AEY, both in terms of retail customers served and regulated rate base. FortisBC Energy serves 56X more retail customers and its rate base is 33X larger than AEY's. FortisBC Energy also has more cost recovery protection through deferral and variance accounts and more revenue stability through a weather normalization clause than AEY. As a gas distributor, FortisBC Energy owns its regulated gas distribution system, whereas AEY owns the electric distribution system and some generation facilities. As discussed in more detail later in the report, investors and credit rating agencies view companies that own generation as higher risk than pure transmission and/or distribution utilities. FortisBC Energy has an allowed ROE of 8.75 percent on 38.5 percent common equity, while AEY currently has the same ROE and a slightly higher equity ratio of 40 percent…[116] FortisBC Electric was awarded an ROE risk premium of 40 basis points above the benchmark utility by the BCUC in the GCOC Stage 2 proceeding. Like AEY, FortisBC Electric has 40 percent deemed common equity. FortisBC Electric is almost 10X larger than AEY in terms of retail customers served and has rate base about 15X greater than AEY. FortisBC Electric supplies approximately 45 percent of its load through company-owned generation, while AEY supplies about 9 percent, indicating that FortisBC Electric has relatively more generation risk.[117]

209. "Section IV — Risk Assessment" of the Concentric report listed the following risks:

- small size,
- generation risk,
- fuel and purchased power risk,
- volume/demand risk,
- regulatory environment,
- deferral/variance accounts, and
- competition from alternative fuels.[118]

210. The Board considers the two greatest risks to be size and generation. Discussion of the remaining listed risks follows. Fuel and purchased power are addressed through

[116] Exhibit BB-1, Application, Attachment 8.1, pages 4-5.
[117] Exhibit BB-1, Application, Attachment 8.1, page 5.
[118] Exhibit BB-1, Application, Attachment 8.1, page 1.

deferral accounts. AEY has stated its preference to manage volume/demand risk. Regarding regulatory environment, Concentric has stated that traditional cost of service regulation is generally considered less risky than incentive regulation.[119] AEY is under cost-of-service regulation, while FortisBC Energy and FortisBC Electric are under incentive regulation. Concentric did conclude that AEY was at higher risk than other companies due to not having a variance account for weather-related volume risk. As AEY prefers to manage its sales volume risk, the Board does not accept Concentric's conclusion that AEY faces increased regulatory risk because it does not have a weather-related volume risk deferral account. The Board's view is that AEY faces less regulatory risk than FortisBC Energy and FortisBC Electric because it is under cost-of-service regulation. Additionally, Concentric did not state that AEY deserved a risk premium for variance/deferral accounts.[120] Regarding competition for alternative fuels, Concentric submitted that FortisBC Energy faced competition from electric heat among residential customers and to a lesser extent than did PNG-West. However, Concentric concluded that this type of risk was difficult to quantify and likely does not have a material effect on the risk profile of AEY.[121]

211. Based on the foregoing, the Board concludes that in determining relative risk for AEY, the Board should look at size and generation risk.

212. For the comparators provided by Concentric,[122] the Board does not accept the use of FortisBC Electric for the lower boundary. Although FortisBC Electric is larger than AEY, its generation assets are a quantum level higher than the generation assets of AEY. Concentric referenced the BCUC GCOC Stage 2 proceeding[123] and the awarding of a 40-basis-point risk premium to FortisBC Electric. Part of the determination of the risk premium for FortisBC Electric was:

> The evidence supports the findings that FBC [FortisBC Electric] faces additional price competitiveness risk as compared to the Benchmark and in addition there is some additional risk related to small size. The Panel finds no substantial difference in supply risk as compared to the Benchmark, and, regarding operating risks, we found there was no basis on which to establish the potential impact of any differential in risk.[124]

213. Price competitiveness was a major factor in determining the risk premium for FortisBC Electric. Concentric concluded that competitiveness (from alternate supply) did not have a material impact on the risk profile of AEY. Generation assets for FortisBC Electric are materially higher than for AEY. Similarly, the generation assets for Maritime Electric are materially higher than those of AEY. Maritime Electric procures its power from a different jurisdiction.[125] Due to these factors (competitiveness, relative amount of generation assets), the Board finds that AEY is not directly comparable to FortisBC

[119] Exhibit BB-1, Application, Attachment 8.1, page 25.
[120] Exhibit BB-1, Application, Attachment 8.1, page 26.
[121] Exhibit BB-1, Application, Attachment 8.1, pages 26-27.
[122] FortisBC Electric for the lower boundary, PNG-West for the upper boundary, and settling on an ROE equivalent to Maritime Electric.
[123] Exhibit BB-1, Application, Attachment 8.1, page 5. The reference was to BCUC Generic Cost of Capital Proceeding (Stage 2) Decision, March 25, 2014 at page 113.
[124] Exhibit BB-1 BCUC Generic Cost of Capital Proceeding Stage 2 Decision, Order G47-14, March 25, 2014, page 86 (public document available at www.ordersdecisions.bcuc.com)
[125] Exhibit BB-1, Application, Attachment 8.1, page 21. The Board views cross-jurisdictional transactions as facing higher regulatory risk than those transactions occurring within a single jurisdiction.

Electric or Maritime Electric. Accordingly, the Board does not find generation to be a significant risk for AEY in relation to the risk of Fortis BC.

214. Further, in terms of comparisons to Maritime Electric, the Board notes that its ROE was determined through a settlement agreement. There is no evidence on the record of this proceeding indicating the trade-offs that may have occurred during the negotiation process or how the ROE level was determined. As a result, the Board gives little weight to the ROE determined by way of a settlement agreement.

215. Concentric stated that PNG-West was larger than AEY and added that PNG-West was awarded a higher risk from the BCUC due to customer growth, market demand and throughput risk (due to the loss of a major customer, which caused total system throughput to decline by 87 percent from 2003-2012). Concentric referenced the BCUC GCOC Stage 2 decision for this information. These circumstances do not apply for AEY. Therefore, the Board concludes that AEY is not directly comparable to PNG-West.

216. Although earnings variability has been mentioned by Concentric, the Board also notes that AEY has been able to consistently meet or exceed forecast earnings levels.[126]

217. The Board took note of Concentric's view that the extremely small size of AEY is an important risk factor for the purposes of establishing an appropriate risk premium for AEY.[127]

218. Based on the evidence, the Board has determined that small size is the most significant factor to be considered in determining a risk premium for AEY.

219. The evidence on this record shows that BCUC has set a premium for a small size utility at 25 basis points.[128] This Board accepts that a 25-basis-point premium over the BCUC benchmark utility is reasonable for this jurisdiction.

220. Further, as AEY will have an equity thickness[129] greater than that of the BCUC benchmark utility, the Board is of the view that this will compensate AEY for the other differences between it and the benchmark utility.

221. Therefore, the Board approves an ROE of 9.00 percent for AEY for both test years. AEY is to reflect this change in its compliance filing to this decision.

8.1.5 Common equity ratio

222. AEY requests to maintain the previously approved common equity ratio of 40 percent for each of the test years of 2016 and 2017.

223. John Maissan supported AEY's request for an equity thickness of 40 percent.[130]

[126] Exhibit B-9, YUB-YECL-63(b).
[127] Exhibit BB-1, Application, Attachment 8.1, pages 19-20.
[128] Exhibit B-9, YUB-YECL-62(a).
[129] Equity thickness refers to the ratio of debt to equity of a utility.
[130] JM Final Argument, page 6.

224. UCG submitted:

> … that linking AEY's return on equity to cost of capital formulas developed in other jurisdictions will reduce regulatory costs but should also warrant a review of equity thickness of AEY's capital structure. UCG submits that AEY's equity thickness should be reduced to 37% to match the level established by the Alberta Utilities Commission for its benchmark utility.[131]

8.1.5.1 Views of the Board

225. In Board Order 2014-06, the Board states:

> In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application… Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.[132]

226. The Board continues to view that an equity thickness of 40 percent for AEY is reasonable for the reasons set out above. No evidence was presented in this proceeding in support of another approach. The Board does not accept the submissions of UCG on this issue because no evidence was presented in support of these submissions or the use of an Alberta utility as a comparator in the current proceeding. The Board finds that AEY is to maintain an equity thickness of 40 percent.

8.1.6 Cost of debt

227. AEY discussed its forecast for long-term debt rates in the Application.[133] AEY used an average long Canada bond rate and applied a spread to determine the forecast debenture rate. The following was provided by AEY:

Table 15. **Forecast long-term debt rates**

	2016	**2017**
Long Canada Bond Rate	1.90% - 2.70%	2.30% - 3.30%
Credit Spread	1.80% - 2.20%	1.80% - 2.20%
Debenture Rate	3.70% - 4.90%	4.10% - 5.50%

[131] UCG Final Argument, paragraph 136.
[132] Board Order 2014-06, Appendix A: Reasons for Decision, page 54.
[133] Exhibit BB-1, Application, pages 8-4 to 8-5.

Recommended Rate	4.30%	4.80%
Issue Costs	0.05%	0.05%
Recommended All-in Rate	4.35%	4.85%

Source: Exhibit BB-1, Application, page 8-5.

228. AEY updated its cost of debt numbers in its October 24, 2016 update. The all-in rates were revised to 3.77 percent for 2016 and 4.07 percent for 2017.

8.1.6.1 Views of interveners

229. CW argued that AEY's cost of new debt has a pattern of over-forecasting, and noted that in 2014, the cost of debt was 0.96 percentage points lower than forecasted and for 2015, new debt was 1.08 percentage points lower than forecasted. CW further stated that AEY was protected in 2013 when actual cost was higher than forecasted, as actual cost was determined and approved by the Board for that year.[134]

230. John Maissan argued that for the years 2008-2015, the actual rates for cost of debt were never above the approved rates for cost of debt, but were usually below the approved rates. Mr. Maissan referenced the response to JM-AEY-14 in support of this argument and recommended a cost of debt rate of 4.35 percent for both test years.[135]

231. UCG, based on Board Order 2013-01, recommended that the Board adopt a historic formulaic approach of 120 basis points for forecasting future debt costs.[136]

8.1.6.2 Applicant responses to interveners

232. AEY argued that CW's evidence in relation to a pattern of over-forecasting debt rates should be ignored because AEY actually under-forecasted the rate for cost of debt in one of the years used by CW. AEY added that its October 24, 2016 update to the rate for cost of debt exceeded the recommended reduction in debt rates recommended by CW.[137]

233. AEY submitted that the UCG recommendation that the historical formulaic approach for determining rates for cost of debt should be used for AEY should be rejected due to lack of evidentiary support.[138]

8.1.6.3 Views of the Board

234. The Board notes that AEY did update its cost of debt in its October 24, 2016 update and that update was in response to YUB-YECL-73. The Board also notes that in Argument and Reply Argument, none of the interveners commented on the update to cost of debt.

235. The Board has reviewed the submissions on cost of debt. Originally, AEY forecasted the long Canada bond rate to be 2.50 percent for 2016 and 3.0 percent for

[134] CW Final Argument, paragraph 33.
[135] JM Final Argument, page 4.
[136] UCG Final Argument, paragraphs 152-154.
[137] AEY Final Argument, paragraphs 98-99.
[138] AEY Reply Argument, paragraph 81.

2017. In its update, AEY revised those long Canada bond rates to 1.92 percent for 2016 and 2.22 percent for 2017. It appears that AEY has maintained a credit spread of 1.8 percent.

236. The Board is persuaded by the submissions of Mr. Maissan that the AEY response to JM-AEY-14 show that actual costs of debt are never above and are consistently below forecast levels. For this reason, the Board rejects AEY's forecast for 2016 cost of debt.

237. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November[139] of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision.

238. Further, in YUB-YECL-73(b), AEY was asked to provide the sources for the long Canada bond rate and credit spreads. Although AEY did provide sources, AEY did not explain the manner in which it determined its credit spreads.

239. In response to YUB-YECL-73(a), AEY provided its historical long Canada bond rates and credit spreads for the years 2011-2015. For that period, the average credit spread was approximately 1.6 percent.

240. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision.

8.2 No Cost Capital

241. AEY discussed No Cost Capital (NCC) in its Application. It stated that NCC related to the balances for deferred pensions including Other Post Employment Benefit (OPEB) plans and the Reserve for Injuries and Damages (RID).

242. OPEB plans are administered on a combined basis with Canadian Utilities Limited and AEY is assessed a percentage of its payroll at a rate calculated for the plan as a whole. AEY continues to use the cash basis for its pension plan and the OPEB plan. The OPEB plan covers such items as drug, health and dental costs for retirees.

[139] 2012 is the only year where the issuance was after November 1. The issuance date for that year was November 14.

243. The RID is as an account used for uninsured and uninsurable losses and the deductible portion of insurance claims. Attachments 8.2 (Beaver Creek House Fuel Spill — $109,700) and 8.3 (Fish Lake #1 Spillway Failure — $100,000) to the Application provided details of the two incidents that have been included in the RID account.

244. The following continuity schedule for NCC was provided by AEY:

Table 16. **Continuity for NCC Mid-Year Balance — 2013 to 2017 ($000s)**

	2013	2014	2015	2016	2017
	Actual	Actual	Actual	Test Period	
Total No Cost Capital	165	(24)	446	660	667

Source: October 24, 2016 Update, Schedule S8.4.

8.2.1 Views of the Board

245. The Board finds AEY's updated NCC costs to be reasonable and approves the updated amounts, subject to any impacts from other sections of this decision.

9 Capital additions

246. AEY submitted that capital additions were primarily driven by the requirement to upgrade, enhance and replace components on the distribution and generation systems that have reached the end of their lifecycle, as well as meet system needs due to load growth. AEY's actual and forecasted capital expenditures and additions to rate base for the period from 2013 to 2017 are shown in the following table:

Table 17. **AEY Capital Expenditures and Additions – 2013 to 2017 ($000s)**

	Actuals			Forecasts	
	2013	2014	2015	2016	2017
Generation	5,574	8,599	3,060	6,630	5,316
Distribution	7,268	6,236	6,232	7,659	8,994
General Property & Equipment	2,516	2,002	1,402	759	1,008
Capital expenditures total	15,358	16,837	10,694	15,048	15,318
Capital additions to rate base	14,321	18,849	10,252	14,234	14,907

Source: Application, Page 9-1; Application, Schedule 9.1.

247. Using the numbers in the above table, the capital expenditures for the test period are forecasted to increase by approximately 40 percent each year when compared to 2015. Capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively, when compared to 2015.

248. Generally, with the exception of projects described in the following sections, AEY's capital additions are categorized as generation, new extensions, distribution improvements, street and sentinel lights, meters and general property and equipment. Generic descriptions of each category are provided in pages 9-1 to 9-5 of the Application, while a listing of the projects that make up the dollars shown Table 17

(above) of this order are provided in Schedules 9.1 and 9.2 of the Application. A listing of the capital expenditure information for 2016 and 2017, as well as project descriptions for those projects greater than $100,000, are found in Attachment 9.1 and Attachment 9.2, respectively. Full business cases for major capital projects, $500,000 or greater, are included in the Application's appendices.

249. AEY provided the following information that shows that its controllable capital was within 3.2 percent the capital expenditure amounts approved in Board Order 2014-06 for its 2013-2015 GRA. The following table shows the variances in AEY's controllable capital expenditures between its actual and approved amounts for 2013-2015:

Table 18. **Controllable Capital Expenditures — 2013 to 2015 ($000s)**

2013-2015 GRA			
	Actual	**Approved**	**Variance (%)**
New Extensions	6,141	15,480	60.3%
Contributions	(4,866)	(13,039)	62.7%
Net New Extensions	1,275	2,441	47.7%
"Controllable" Capital	36,748	37,955	3.2 %
Total Net Capital	38,023	40,396	5.9%

Source: Exhibit B-4, CW-YECL-1.

9.1 Views of interveners

250. Mr. Maissan pointed out that the projects listed in Attachments 11-1 to 11-6 of the Application,[140] relating to project cost overruns, exceeded the forecast budgets by a total of $4.7 million. The 2013 to 2015 forecast controllable project expenditures spent is $32.048 million. Mr. Maissan stated that AEY underspent by $5.947 million or by 15.65 percent of the original forecast. Mr. Maissan went on to state:

> … a significant number of forecasted capital projects did not get done, had they been done the "controllable" capital budget would have been exceeded by $4.7 million or more. Many projects have been dropped or deferred, but AEY provided no information on them.[141]

251. Mr. Maissan recommended that the Board order AEY to provide detailed information on capital projects that have been deferred or dropped, and the level of detail should be commensurate with the detail required for AEY capital forecasts. Mr. Maissan further recommended that the Board reduce the controllable capital budget, after any and all other adjustments, by three percent. The Board should further order AEY to indicate in a compliance filing where these cuts were made.[142]

[140] Exhibit BB-1, Application, Project Completion Summaries Table, page 11-3.
[141] JM Final Argument, page 7.
[142] JM Final Argument, page 7.

9.2 Applicant responses to interveners

252. Responding to Mr. Maissan's submission, AEY referred to its response to YUB-YECL-11(b) Attachment 1, a spreadsheet that includes a list of all projects approved capital projects and deemed capital projects from the 2013-2015 period. AEY pointed out that in this spreadsheet, projects with variances of 10 percent and greater than $50,000 are accompanied by a corresponding explanation. AEY noted that in its Application it had resubmitted updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but have been deferred to the 2016-2017 test period.[143]

253. AEY stated that the arbitrary reduction of the capital forecast, as recommended by Mr. Maissan, ignores the significant amount of evidence on the record supporting the need and prudence of the capital projects within the capital forecast, pointing out that the capital program throughout 2013-2015 was significantly higher than what AEY has experienced in recent years. AEY submitted that it has incorporated the learnings gained from this experience into its capital forecast by making adjustments in its forecasting methodology and assumptions. AEY submits that the evidence on record does not support Mr. Maissan's recommended reduction.

9.3 Views of the Board

254. The Board has reviewed AEY's capital addition forecasts and corresponding information and considers that AEY has provided sufficient support for its capital forecast for 2016-2017. Although the increase in capital additions to rate base for 2016 and 2017 are forecasted to increase by 39 and 45 percent respectively from 2015, the capital additions are reasonable when compared to the prior three years' actual capital additions. Subject to the Board's findings in the subsections that follow, the forecast capital additions and capital expenditures have been supported by business cases and the Board accepts the explanations in the updated business cases for significant projects that were previously approved in the 2013-2015 GRA, but were deferred.

255. For these reasons, Mr. Maissan's recommendation for a general cut for AEY's controllable capital budget is not warranted.

9.4 Distribution Plant additions

256. AEY provided the following information related to distribution plant additions for the period 2013 to 2017:

Table 19. **Distribution Plant Additions — 2013 to 2017 ($000s)**

	Actual	Approved	Actual	Approved	Actual	Approved	Forecast	
	2013	2013	2014	2014	2015	2015	2016	2017
New Extensions	2,350	5,033	1,693	5,147	2,098	5,300	2,160	3,388
Distribution Improvements	4,002	4,021	3,980	4,457	3,326	3,875	4,346	4,178
Street & Sentinel Lights	536	420	322	945	466	813	585	1,132
Meters	308	600	166	204	234	207	200	204

[143] AEY Reply Argument, paragraph 96.

Transformers & Regulators	72	10	75	10	108	10	368	92
Distribution in Total	7,268	10,084	6,236	10,762	6,232	10,205	7,659	8,994

Source: AEY Application, Schedule 9.1.

257. AEY pointed out that, as a result of AEY's forecasting, the 2016 forecasts represent a 41-percent reduction compared to the 2015 approved forecast.[144]

9.4.1 Views of interveners

258. UCG noted that total actual distribution plant additions for the 2013 to 2015 timeframe were $19.736 million, compared to the approved forecast amount of $31.051 million. UCG submitted that ratepayers have paid the costs of $11.315 million in forecasted distribution plant additions that never took place within the test years.

259. Given this recent track record of overestimating plant additions, UCG recommended that the distribution plant forecast for the 2016-2017 test period be reduced by 40 percent.[145]

9.4.2 Views of the Board

260. Regarding the UCG comments that forecasted capital additions were greater than actual capital additions, the Board notes that the approved forecasted plant additions ($31.051 million) for 2013 to 2015 have been subsequently trued up to now reflect the actual plant additions ($19.736 million) for 2013 to 2015. It is the actual plant additions that are now reflected in the 2015 actual closing balances that are used to inform the 2016 test year opening capital balances. Furthermore, this is standard process for forward-looking (or prospective) cost-of-service jurisdictions.

261. The Board has reviewed AEY's forecasted planned additions to distribution and corresponding information and considers that AEY has provided sufficient support for its distribution plant additions for 2016-2017. With respect to AEY's test year distribution forecasts compared to previous year's actual and approved numbers, it appears that the primary reason for the increase is related to distribution improvements. The Board's findings related to distribution improvements are addressed in section 9.4.4. Subject to the findings in that section, the Board considers AEY forecasts to be reasonable for distribution plant additions and does not agree with UCG's recommendation to reduce the 2016-2017 test-period forecasts.

9.4.3 New Extensions

262. With respect to New Extensions, AEY stated that the forecast is based on discussions with the Yukon government, the City of Whitehorse and First Nation governments. AEY holds a seat on the Development Review Committee with the City of Whitehorse. As a result, AEY has contact with developers and engineering firms, which informs the new extension forecast. AEY submitted that it also considers historical customer additions in formulating its forecasts to specifically account for walk-in customers who may require service during the test years.

[144] AEY Reply Argument, paragraph 126.
[145] UCG Final Argument, paragraphs 175 to 176.

263. AEY submitted that the reason for lower new extensions expenditures as compared to previously approved numbers is slower economic growth than previously anticipated. AEY added that new extensions are a capital cost not at the control of AEY and are dependent on development within the communities in which the company operates.[146]

264. AEY submitted that it uses the best information available when preparing its forecasts, which includes any lessons learned from past test periods. AEY reiterated that its new extension forecast is based on "historical actual experience and incorporated information from the Yukon Government, the City of Whitehorse, and First Nation Governments … there is no systemic forecast error and … the forecast has no relation to, or correlation with the 2013-2015 forecast."[147]

9.4.3.1 Views of interveners

265. CW noted that AEY admitted it over-forecasted capital additions related to new extensions over the 2013 to 2015 period. Furthermore, taking customer contributions into account, the forecast for net new extensions over the period is 47.7 percent higher than actuals. CW submitted that the systematic over-forecasting results in customers paying for capital that is not actually put into service. Accordingly, CW recommended the Board reduce the 2016-2017 test period forecast for net new extensions by 47.7 percent to account for the systemic forecast error.[148]

9.4.3.2 Views of the Board

266. With respect to the argument put forth by CW, the Board is not convinced that a three-year period of actuals being lower than approved amounts can be classified as systemic. The Board accepts Mr. Tenney's testimony on behalf of AEY that overall, the three-year forecast period was fairly accurate.[149] However, the Board notes that might not be true on a line-item-by-line-item basis. Mr. Tenney also stated in testimony:

> With the exception that there are capital projects that are customer driven and with our obligation to serve, we think those are a given that the need to move forward.[150]

267. Mr. Massie added:

> And just speaking specifically to the capital program and specifically to new extensions here, we have realized that, you know, we missed the mark in new extensions for that test period. I'd say that we've reflected it in our '16 and '17 forecasts.[151]

268. The Board accepts AEY's testimony that it has adjusted its test period forecasts to account for historical over forecasting. The Board does not accept CW's and UCG's recommendations to reduce AEY's new extension forecast.

[146] Exhibit B-4, CW-YECL-1.
[147] AEY Final Argument, paragraph 130.
[148] Exhibit C3-3, CW Evidence, A8.
[149] Transcript, Volume 3, page 441, lines 13 to 14.
[150] Transcript, Volume 3, page 442, lines 6 to 9.
[151] Transcript, Volume 3, page 442, lines 17 to 22.

269. Furthermore, the Board notes that the 2016 new extension forecast is three percent greater than 2015 actuals, and the 2017 forecast is 2.2 percent greater than the 2016 forecast, after the Whistle Bend Stage 3 project is accounted for in the forecast.

270. In the Board's view, AEY is taking into account current economic conditions in the Yukon and information available to it at the time of preparing the forecast. Moreover, the Board notes that AEY's submission that indicated that year-to-date costs for new extensions, as of October 31, 2016, are $2.116 million, or 98 percent of the 2016 forecast.[152]

271. For these reasons, the Board approves AEY's forecast as filed.

9.4.4 Distribution improvement projects

272. AEY submitted that distribution improvement projects generally fall into four major categories: (1) system performance projects, (2) life extension projects, (3) system replacement projects, and (4) "forced" projects. AEY clarified that these projects are required to maintain system performance at an acceptable level and that this category of capital projects includes system protection, voltage, current and line clearance projects.[153] AEY added that it tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast.[154]

273. AEY submitted that the proposed test period forecast distribution improvement projects are prudent in that they ensure the continued supply of safe and reliable electricity to AEY's customers at a reasonable price. Accordingly, AEY submitted that the Board should approve the 2016-2017 distribution improvements as applied for.[155]

274. AEY pointed out that it files KPI (key performance indicators) reports on an annual basis. AEY submitted that the reports are available on the Board's website and added that that the last such report for year 2015 was filed on May 4, 2016.[156]

9.4.4.1 Views of interveners

275. UCG noted that system improvement expenditures increased an average of $3.75 million per year over the period from 2010 to 2015. UCG further noted that AEY proposed system improvement expenditures of $4.346 and $4.178 million in 2016 and 2017 respectively, but has provided no evidence of expected system performance improvements with respect to line losses and interruption indices. UCG included the following in argument:

> UCG submits that without an established benchmark, the Board and ratepayers cannot determine how well AEY is actually performing with respect to SAIFI (System Average Interruption Frequency Index), SAIDI (System Average Interruption Duration Index) and CAIDI (Customer Average Interruption Duration Index) reliability performance indices. UCG submits that the Board

[152] AEY Reply Argument, paragraph 91; Transcript, Volume 3, page 509, line 25, to 510, lines 1-2.
[153] Exhibit BB-1, Application, Page 9-2.
[154] Exhibit BB-1, Application, Page 9-3,
[155] AEY Final Argument, paragraph 138.
[156] AEY Reply Argument, paragraph 46.

> should establish performance and reliability benchmarks and AEY should be directed to report its actual performance against these benchmarks.[157]

276. Considering the above, UCG submitted that AEY should be denied distribution expenditures in 2016 and 2017 since evidence has not been provided that demonstrates a benefit to customers.

9.4.4.2 Views of the Board

277. The Board approves AEY's proposed distribution improvement expenditures as filed. Nonetheless, with respect to system performance projects, the Board notes AEY submission that it:

> … tracks distribution system performance on an ongoing basis and the performance is reviewed when preparing the capital forecast. To this end, AEY reviews unplanned outages that may be attributed to system deficiencies, prepares a report for each, and implements corrective action.[158]

278. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings.

9.4.5 Meters

279. AEY submitted that capital additions for meters should include new meter installations that are required to replace end-of-life meters consistent with Measurement Canada requirements. This category of capital additions also includes the installation of new meters required to accommodate load growth associated with customer requests for service. The capital meter additions forecast is based on known areas of development and expected connection repairs.

280. AEY pointed out that it purchases meters from ATCO Electric at cost and, in so doing, is able to take advantage of the economies of scale realized by ATCO Electric in its meter purchases. This is a significant benefit to AEY and its customers. AEY submitted "this is undoubtedly the least cost alternative given that it is able to purchase its meters, but with the buying power of a utility the size of ATCO Electric."[159] Furthermore, other than AEY and its customers benefiting from this relationship, AEY submitted that it is unclear as to what benefit could be derived by the ATCO family of companies, given that the meters are purchased at cost.

[157] UCG Final Argument, paragraph 231.
[158] AEY Final Argument, paragraph 136.
[159] AEY Reply Argument, paragraph 136.

9.4.5.1 Views of interveners

281. With respect to meter replacement and new installations, UCG commented that over the period 2013-2015, AEY had actual expenditures of $708,000 that were well below the approved $1 million total. UCG submitted that this significant over-forecasting trend should be used to reduce the forecasts proposed for 2016 and 2017. UCG also referred to AEY's submission that it purchases meters from ATCO Electric's meter shop in Grande Prairie. UCG submitted that there should be further clarification on how this arrangement was determined to be the least cost alternative supply point and whether the affiliate relationship had been used to provide benefits to the ATCO family of companies.[160]

9.4.5.2 Views of the Board

282. The Board accepts AEY's submission that it is able to purchase its meters at cost from ATCO Electric. Accordingly, the Board finds that no further information is required. The meters are supplied by the affiliate at cost, and the mere existence of the affiliate arrangement for the provision of these meters, in these circumstances, does not merit further clarification by AEY at this time. UCG's request is denied.

9.5 Conversion of existing LED streetlights

283. AEY indicated that it has been in discussions with its customers, some of which are municipalities, regarding recent developments related to the conversion of existing streetlights to light-emitting diode (LED) lamps. Considering there is capital outlay associated with the conversion of existing streetlights to LED, AEY submitted that it is seeking the Board's direction

> … as to the appropriate method of accounting for the capital costs associated with customers requesting conversions of existing streetlights to LED. ATCO Electric Yukon considers there to be two available options:
>
> (1) A full customer contribution required for all associated capital costs; or
>
> (2) All capital costs associated with requested conversions would be a system cost, not subject to a customer contribution.[161]

284. AEY explained that the rationale for this project being a system cost would be that the initial streetlight cost was contributed by the customer when the streetlight was originally installed. At the end of useful life when the asset needs replacement, the customer is not required to contribute again and the cost becomes a system cost.[162]

285. AEY acknowledged the benefit of reducing load on the electrical system and that the longer lifespan of equipment used under this project could lead to reduced costs in operation and maintenance of the lights. AEY submitted that converting all existing high-pressure sodium (HPS) streetlights to LED streetlights in AEY's communities would cost approximately $2 million and the project would need to be completed over several years due to resource constraints.

[160] UCG Final Argument, paragraphs 221 to 222.
[161] Exhibit BB-1, Application, page 9-3.
[162] Exhibit B-9, YUB-YECL-10(c).

286. AEY provided two cost-benefit analyses for converting lights in thermal communities and hydro communities for each of the two options: customer contributions or system costs.[163] The cost-benefit analyses showed that a greater net present value (NPV) would result if the conversions were done in diesel-served (thermal) communities compared to hydro communities. AEY reiterated that it is not applying for approval of a wholesale replacement of all existing HPS streetlights but is seeking Board direction as to the appropriate method of accounting for the costs associated with customer conversions of existing streetlights to LED.[164]

9.5.1 Views of interveners

287. Mr. Maissan indicated his support for the LED-conversion project and recommended that the Board direct AEY to proceed with the conversion of streetlights (i.e. HPS to LED lights) as a system cost and that priority be given to diesel-served communities.

288. CW indicated its support for the conversion of existing streetlights to LED lamps. However, CW submitted that it is inappropriate for AEY to request the Board to issue direction as to the method of accounting for the associated capital costs in the absence of a fully supported proposal by AEY on that issue. Accordingly, CW recommended that the Board direct AEY to submit a proposal, supported by evidence, which can be tested by the Board in order for it to make a determination on this issue.

9.5.2 Applicant responses to interveners

289. AEY submitted that it is not clear as to what additional information CW is proposing that AEY file with the Board. From AEY's perspective, the decision is relatively straightforward in that either the conversion costs are treated as a system cost or the local municipality must pay for the conversion cost as a contribution in aid of construction. AEY pointed out that economic analyses of both treatments as well as the total estimated costs involved are on the record. All parties have had an opportunity to submit IRs and cross-examine AEY with respect to the information. AEY submitted that the record is complete and the Board has ample information to render a decision on the treatment of costs for streetlight conversions.

> Moreover, the treatment of such costs will likely inform the decisions of the relevant communities and/or municipalities with regard to such conversions.[165]

290. AEY asserted that requiring it to come forward with a fully supported proposal is entirely unnecessary and would only serve to add inefficiencies to the regulatory process.

9.5.3 Views of the Board

291. The Board supports AEY's rationale for a streetlight project to be treated as a system cost, as outlined:

[163] Exhibit B-9, YUB-YECL-10(b) Attachment 1.
[164] Exhibit B-4, CW-YECL-27 (h).
[165] AEY Reply Argument, paragraph 95.

> … the initial light asset cost was contributed by the customer when the light was originally installed in accordance with the approved Terms and Conditions of Service at the time. At the end of useful life when the asset needs replacement the customer is not required to contribute again and the cost becomes a system cost.[166]

292. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost.

293. With respect to LED streetlight installations that are not end-of-life conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction.

9.6 Project cost overruns (related to Direction 13 — Board Order 2014-06)

294. Responding to Direction No. 13 of Board Order 2014-06, in relation to project cost overruns, AEY included project completion summaries for all projects that were forecast in AEY's 2013-2015 GRA for which actual costs were 100 percent and $100,000 greater than the original forecast. AEY's compliance with Direction 13 is discussed in section 11 of this decision.

295. The following table contains the list of projects and the related attachment in section 11 of the Application wherein the project descriptions and summaries are provided. Actual and approved forecast costs are included in the summaries, as well as explanations for the variances:

Table 20. **Project Completion Summaries ($000s)**

Project	Attachment	Approved Forecast	Actuals
Fish Lake Dyke Upgrade	Attachment 11.1	1,720	2,552
Old Crow Plant Expansion	Attachment 11.2	1,950	4,566
Beaver Creek PLC Upgrade	Attachment 11.3	180	377
McIntyre Subdivision Rebuild	Attachment 11.4	725	1,453
Deep Creek Subdivision Connection	Attachment 11.5	60	213
Old Crow Staff Accommodations	Attachment 11.6	100	274

Source: Exhibit BB-1, Page 11-3, Attachments 11.1 to 11.6.

[166] Exhibit B-9, YUB-YECL-10(c)

296. AEY provided business cases for projects where the actual costs were in excess of $100,000 and for which no business case was provided. The following table includes the list of projects and the actual costs:

Table 21. **Business Cases for Completed Projects ($000s)**

Project	Attachment	Actuals
Old Crow #2 Replacement	Attachment 11.7	161
Whistle Bend Subdivision Stages 1 & 2	Attachment 11.8	513
Whistle Bend Underground Residential Service	Attachment 11.9	116
City of Whitehorse Range Road Widening	Attachment 11.10	188
4L314 Chilkoot Way Upgrade	Attachment 11.11	483
Azure Road Extension	Attachment 11.12	151
2nd Ave Rebuild	Attachment 11.13	115

Source: Exhibit BB-1, Page 11-4, Attachments 11.7 to 11.13.

9.6.1 Views of interveners

297. With respect to the Old Crow plant expansion project, which went over-budget by $2.616 million, Mr. Maissan asserted that AEY has been operating in Old Crow for many years and submitted that AEY should have suspended and re-assessed the project when it ran into design cost overruns and local logistical difficulties. Mr. Maissan recommended that the Board retain experts to review and audit the project execution process and cost, or the Board disallow $1 million of the $2,616 million cost overruns and remove it from rate base.[167] With respect to the Old Crow Unit 4 Addition project, Mr. Maissan recommended that the Board direct AEY to provide a business case for this project, as it was completed $112,000 over budget.[168]

298. UCG expressed concerns with the significant expenditures over approved budget amounts for many of the capital projects that had been previously approved. UCG submitted, “If there is no evidence that these extra costs were prudently incurred, they should not be allowed to be added to AEY’s rate base.”[169] UCG stated that additions to AEY’s rate base should be limited to allowed cost estimates unless AEY can provide evidence that the cost overruns were prudently incurred. In particular, UCG submitted that the doubling of the cost for the McIntyre Subdivision Rebuild should be the responsibility of AEY, not ratepayers. It concluded with respect to the McIntyre Subdivision Rebuild:

> AEY’s evidence is that this project went well beyond the Board approved level because the location and installation of the existing underground system would be in constant conflict with the installation of the new system. This along with other issues resulted in a requirement to develop an entirely new project scope. This resulted in AEY incurring an additional $728,000 in costs (for a project originally assumed to cost $725,000) and doubling the cost of the project.[170]

[167] JM Final Argument, page 8.
[168] JM Final Argument, page 9.
[169] UCG Final Argument, paragraph 160.
[170] UCG Final Argument, paragraphs 177.

299. UCG further submitted that AEY should not be able to arbitrarily add capital projects to rate base that have not been previously approved by the Board. [171] Furthermore, expressing concerns respecting the rapid increase in AEY's rate base in the 2013-2015 timeframe, UCG submitted that AEY should be required to submit detailed asset management plans and/or distribution system plans, the elements of which "will drive the development of investment and maintenance for the test year(s) and beyond.[172]

9.6.2 Applicant responses to interveners

300. Notwithstanding the comprehensiveness of the Old Crow business case, as acknowledged by Mr. Maissan, AEY submitted that project timing was restricted given the timing of the construction of the ice road. Furthermore, the magnitude and extent of the many challenges that arose could not have been foreseen. AEY submitted that although the business and community need did not change, AEY proceeded with the project knowing the costs would be fully examined in a future GRA. AEY confirmed that it would be:

> … submitting a Post Completion Summary of the project, that clearly indicates the variances, and gives the Board and Interveners an opportunity to examine the Project during the entirety of a regulatory proceeding is the most appropriate process, without putting the supply of power to the community at risk.[173]

301. Respecting Mr. Maissan's recommendation that AEY submit a business case for the Old Crow Unit 4 addition costs because project costs exceeded the original estimate by more than $100,000, AEY pointed out that the costs did not exceed 100 percent of the approved forecast. As such, AEY submitted "the business case type description of the cost overrun sought by Maissan is not required" and AEY submitted that there is sufficient information on the record to deem the project useful and prudent.[174]

302. Responding to UCG, AEY replied that it does not arbitrarily add capital projects to rate base. AEY's capital expenditure forecasts are based on the best available information at the time of its GRA. AEY submitted that unknown costs that arise and are not included in test period forecasts are subsequently included as actuals in future applications, thus providing the Board and interveners with the opportunity to assess the need and prudency of such costs. AEY submitted that despite UCG's claims, there is ample evidence on the record to demonstrate that all costs related to McIntyre Stage 1 have been prudently incurred. AEY argued that project planning was comprehensive and many assumptions were validated. It could not have predicted what caused the project scope to be adjusted. AEY indicated that, "Project planning and execution was constantly reviewed and updated with the best available information, al while ensuring the customer and Project needs are addressed."[175]

[171] UCG Final Argument, paragraph 162
[172] UCG Final Argument, paragraph 165
[173] AEY Reply Argument, paragraph 104.
[174] AEY Final Argument, paragraph 106.
[175] AEY Reply Argument, paragraph 129.

303. AEY added that there is no evidence on the record indicating that the "capital projects put forward by AEY are not needed or that they have not been completed prudently."[176] With respect to the UCG submission that AEY provide a detailed asset management plan, AEY submitted that such an undertaking is beyond the scope of this proceeding and is being put forward by UCG with limited explanation and no evidence to justify such a request.[177]

9.6.3 Views of the Board

304. The Board notes that in its Application, AEY has provided:

(a) project completion summaries that were forecast in its 2013-2015 GRA, for which actual costs were 100-percent and $100,000 greater than the original forecast; and

(b) business cases for projects where actual costs were greater than $100,000 and for which no business cases were provided.

305. As a result, AEY provided a business case (Appendix 11) for the Destruction Bay Unit 3 replacement where actual costs exceeded the $450,000 forecasted by $184,000. The Board further acknowledges that AEY provided a comparison of forecast and actual costs,[178] accompanied with an explanation for projects with variances of 10 percent and greater than $50,000.

306. When costs are provided in a GRA on a forecast basis, the Board accepts the information available at the time of filing the Application or that becomes available prior to the close of record of the proceeding. Providing the Board with the best available information at the time that it must make its decision assists the Board in determining a revenue requirement for the utility that most closely matches a utility's expected costs given facts known at the time the application was made or before the close of record. It is incumbent on the utility to do so, and for the utility to plan and budget in preparing its forecasts. Unforeseen projects may arise after a Board Order is issued with respect to the forecast test period. In these cases, the Board reviews the project costs and the variances in the subsequent GRA to ensure that the costs were prudently incurred by the utility.

307. Despite the magnitude of some of the variances between forecast and actual capital expenditures for certain capital projects, the Board accepts the variance explanations provided by AEY.

308. Considering the above, the Board accepts the information found in the project completion summaries and business cases for completed projects. No further direction from the Board is required. The projects and their corresponding costs are discussed in the following sections.

[176] AEY Final Argument, paragraph 122.
[177] AEY Reply Argument, paragraph 125.
[178] Exhibit B-9, YUB-YECL-11(b) Attachment 1.

9.7 Major capital projects

309. In the Application, AEY provided 11 business cases found in Appendix 1 to Appendix 11, in support of major capital projects where forecast costs were $500,000 or greater. Major capital projects and the underlying business cases are discussed in the sections below.

9.7.1 Fish Lake System expenditures[179]

310. AEY noted that the Fish Lake hydro system was built around 1950 and the aging infrastructure is coming to the end of its useful life. In order to maintain Inflow Design Flood (IDF) rates and comply with its water licence for Fish Lake, AEY proposed two projects: the Fish Lake Ditch 3 Diversion project and Fish Lake #2 Head Pond Spillway replacement.

9.7.1.1 Fish Lake Ditch 3 Diversion project (Appendix 1)

311. This project was previously approved in AEY's 2013-2015 GRA. On May 31, 2013, AEY was granted a 25-year extension to its water-use licence, HY12-065. AEY submitted that during the water licence application process, it was identified that the Fish Lake Ditch 3 diversion structure and spillway were not adequately built to withstand a 100-year flood event, which is required to meet IDF rates and comply with its water licensing requirements. AEY is planning to replace and upgrade the Ditch 3 diversion structure and spillway to an engineered design that will allow it to meet these requirements. Accordingly, AEY provided an updated cost forecast with respect to this project, which is reproduced below:

Table 22. **Fish Lake Ditch 3 Diversion – 2013 to 2017 — actual and forecast costs ($000s)**

Year	Actuals	Forecasts	Total
2013	16	-	16
2014	51	-	51
2015	67	-	67
2016	-	2,915	2,915
Total	134	2,915	3,049

Source: Exhibit BB-1, Application, Appendix 1, page 2.

9.7.1.2 Fish Lake #2 Head Pond Spillway Replacement (Appendix 2)

312. Investigative repairs of the Fish Lake #2 head pond spillway structure identified that the overall structure was in need of replacement. AEY explained that it will have to replace the existing spillway structure in order to adequately handle IDF flows while maintaining safe access to AEY generation facilities. AEY submitted that the project was designed in 2016 and construction is expected to be completed in 2017. Design and engineering costs are estimated to be $20,000 and the current construction costs are forecasted to be $593,000.

[179] Exhibit BB-1, Application: Appendix 1, Fish Lake Ditch 3 Diversion Replacement and Appendix 2, Fish Lake 2 Head Pond Spillway Replacement.

9.7.1.3 Views of interveners

313. UCG noted that over the period from 2006 to 2015, AEY has spent $11.429 million in capital and $1.96 million in O&M expenditures, while AEY, over the same period, has recovered $5.87 million in revenue requirement from ratepayers. UCG pointed out that AEY is now looking to spend over $3 million on the Fish Lake Ditch 3 replacement project and an additional $0.593 million on the Fish Lake #2 Head Pond Spillway replacement project. Considering the limited amount of total load that is supplied via the Fish Lake plant, it is questionable whether spending this level of funds on a deteriorating plant is providing ratepayers value for their money.[180]

9.7.1.4 Applicant responses to interveners

314. AEY submitted that the projects were being completed on water management structures that direct and control water and water flows in the Fish Lake system in compliance with AEY's water licence. AEY specified with respect to water licensing requirements that:

> As indicated in the Water License, there are maximum and minimum flows that must be maintained throughout the system. Also, a condition of AEY's Water License is that works associated with the License will be maintained to a sound engineering standard (condition 27 of the Water License).[181]

315. AEY further clarified by stating that the specific recommendations for these projects can be found in its *2014 Dam Safety Report*.[182]

9.7.1.5 Views of the Board

316. The Board accepts the need for both of these projects, as they are a condition of the water licence.

317. In the case of the Fish Lake Ditch 3 diversion project, a higher standard in regard to water licence HY12-065 was directed for this project. The change in standard caused a delay as draft designs and spillway channel brushing were required in 2014, additional surveying was necessary to enable updated design models and adjustments in 2015, and further construction and civil work was scheduled to be completed in 2016.

318. The requirement for the Fish Lake #2 Head Pond Spillway Project was not discovered until repairs in 2013 brought to light a sinkhole near this dam structure. Further, investigative work resulting in the 2014 Dam Safety Report recommended replacement of the structure by the end of 2017. Accordingly, the Board does not accept UCG's recommendation to deny the expenditures for this project.

319. The Board accepts the updated forecast costs for the Fish Lake Ditch 3 diversion project as these costs are necessary to meet the standards of the new water licence. The Fish Lake #2 Head Pond Spillway costs have not been challenged in this proceeding, and for the reasons provided in this decision, the Board finds these costs are reasonable.

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[180] UCG Final Argument, paragraphs 218 to 220.
[181] AEY Reply Argument, paragraph 134.
[182] Exhibit B-9, YUB-YECL-14(a), Attachment 1.

9.7.2 Watson Lake Bi-Fuel Project (Appendix 3)

320. AEY is proposing a two-phased, three-year project to convert each of its six diesel generation engines in Watson Lake to bi-fuel. The two phases were described as:

- Phase 1: 2016 – 2017: Source Liquefied Natural Gas (LNG) storage equipment; upgrade Watson Lake plant to meet the safety standard for LNG equipment; install Bi-Fuel technology to one of the six engines; and conduct environmental assessment of engines as directed by Yukon Environmental and Socio-economic Assessment Board (YESAB).

- Phase 2: 2018: Source and install Bi-Fuel technology to the remaining five diesel engines at the Watson Lake plant and increase the volume of LNG storage onsite.[183]

321. If Board approval of the project is received in Q1 of 2017, AEY added that Phase 1 could be completed as early as Q3 of 2017. AEY submitted that Phase 2 of the project is expected to be completed following Yukon Environmental and Societal Assessment Board (YESAB) approval of Phase 1.[184]

322. AEY submitted that this project achieves the federal and Yukon governments' goals of displacing diesel and managing electricity costs by using LNG as an alternative fuel source. Using LNG will reduce diesel consumption of its power generation plant in Watson Lake by approximately 50 percent because it is a cheaper fuel source than diesel. AEY asserted that it "… expects to save hundreds of thousands of dollars annually on fuel costs by the end of this project" and that "These savings would be passed directly on to customers."[185]

323. AEY pointed out that forecasted cost savings are dependent on the differential between the price of delivered diesel and LNG to Watson Lake and the consumption of those fuels. AEY added that the bulk of the delivered LNG price is attributed to the cost of liquefaction and transportation fees. Recognizing the uncertainty as to the future prices for diesel and natural gas, AEY provided 20-year NPV analyses using 12 different scenarios where fuel prices were escalated at differing fixed rates from the 2015 historical price of diesel and natural gas.[186]

324. AEY estimated the total cost of this project to be approximately $5 million, albeit at this time, AEY is seeking approval for $3.3 million to implement Phase 1 of the project. AEY submitted that it will competitively tender each of the major elements of the project,[187] excluding the equipment purchased from ATCO Gas. Further:

> ATCO Electric Yukon proposes to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for

[183] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[184] AEY Final Argument, paragraph 150.
[185] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 1.
[186] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, Table 2, page 7, and Table 3, page 8.
[187] The major elements of the project are described in the Application, Appendix 3, page 3.

> Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[188]

325. AEY estimates the annual incremental O&M costs that are not included in the 2016-2017 forecasted costs but will apply in future years to be approximately $50,000 per year. AEY submitted that the O&M contract specific to the LNG equipment will be competitively tendered, will include periodic maintenance, and will involve additional safety training for AEY's operational staff.[189]

326. Asked why it would choose a new unit that requires field modifications to burn both diesel and natural gas rather than purchasing a new unit that is factory capable of burning both fuels, and with nameplate performance ratings, AEY responded:

> Until AEY receives YUB approval for the Watson Lake Bi-Fuel project, AEY wants to minimize the funds committed to this project. At the time AEY tenders the Watson Lake Unit 2 Replacement, requests will be made for both diesel and Bi-Fuel enabled generating units. AEY will determine what unit is most prudent to purchase. Once the Watson Lake Bi-Fuel project is complete, factory enabled dual fuel units will be considered as generating units are due for replacement.[190]

327. AEY submitted that all of the project-related costs presented in the following table are budgetary, except for the actual costs incurred to date:

Table 23. **Watson Lake bi-fuel project — Phase 1 and 2 capital costs**

	Phase 1			Phase 2
	2012-15	**2016**	**2017**	**2018**
Study costs	$222,000			
Engineering, design, and permitting	$272,000	$55,000	$152,000	$105,000
LNG vaporizer and LNG storage tank			$1,194,000	
Installation (civil, mechanical, and electrical) and boarding			$1,090,000	
Conversion of remaining units to bi-fuel				$700,000
Tank expansion, piping, cryopump and installation				$905,000
Phase sub-total			$2,985,000	$1,710,000
Total				$4,695,000

Source: Exhibit B-9, YUB-YECL-13(b).

328. AEY submitted that it believes there are environmental benefits to this project, which it has previously discussed and which have further been the subject of a review pursuant to the *Yukon Environmental and Socio-economic Assessment Act.* A decision document that supported the project was issued in August 2013.[191]

[188] Exhibit BB-1, Application, Appendix 3, Watson Lake bi-fuel project, page 3.
[189] Exhibit B-9, YUB-YECL-13(e).
[190] Exhibit B-9, YUB-YECL-24(h).
[191] AEY Final Argument, paragraph 143.

329. With respect to project expenditures, AEY submitted that Phase 1 expenditures are the only costs to be incurred within the test period and AEY is seeking to recover those as part of this GRA. AEY explained that Phase 2 of this project is necessary to provide all of the benefits to ratepayers and reduce costs over the long-term by increasing consumption of LNG over the life of the project. AEY submitted that the objective in this GRA is "to obtain Board approval to complete both phases of this Project and AEY will bring forth Phase 2 costs for a prudency determination as part of a future general rate application."[192]

9.7.2.1 Views of interveners

330. With respect to the results of the analysis provided by AEY in its business case[193] and the fuel price scenarios for diesel and natural gas over the period from 2017 to 2037, Mr. Maissan referred to the following:

> Of the 12 scenarios provided in tables 2 and 3, 2 have a negative 20 year NPVs and 3 are below $2 million in NPV. Four scenarios are at $5 million NPV or higher.[194]

331. Mr. Maissan pointed out that the analysis did not account for renewable generation and assumed that all electrical loads will be served by diesel or LNG for the next 20 years. Noting Mr. Tenney's acknowledgement of this on behalf of AEY, Mr. Maissan pointed out that the Yukon's Independent Power Producers (IPP) policy provides for 2,100 MWh of generation to be available to Watson Lake under the standing offer program portion of the IPP policy. Mr. Maissan submitted that any further generation added under the micro-generation program will displace more diesel generation and weaken the economics of the bi-fuel conversion project.[195]

332. Mr. Maissan noted AEY's submission that the project will break even over 20 years when the price per litre of LNG on a diesel-litre-equivalent basis (DLE) is 75.6 percent of the cost of delivered diesel. Considering the price of LNG over the past 12 months, Mr. Maissan argued that the project is uneconomical if LNG were sourced from FortisBC and is just economical if LNG is sourced from AltaGas in Alberta. Mr. Maissan suggested that in his view, there was a high likelihood that the price differential between natural gas and diesel would approach historic levels (i.e. natural gas prices growing closer to diesel prices). If this were to occur, it would make the project uneconomical regardless of which supplier is liquefying and transporting the natural gas.[196]

333. Considering the above, Mr. Maissan recommended that the Board deny the Watson Lake bi-fuel project. Mr. Maissan further recommended that of AEY's project-related costs to date, approximately $549,000 ($494,000 + $55,000) be amortized over a five-year period. On a related matter, Mr. Maissan suggested that the

[192] AEY Final Argument, paragraph 154.
[193] Exhibit BB-1, Application, Appendix 3, Table 3, page 8.
[194] JM Final Argument, page 12.
[195] JM Final Argument, page 13.
[196] JM Final Argument, page 14.

Board direct AEY to "… channel its off-diesel efforts into the acquisition of local renewable energy sources, including the issuance of an RFP for renewable energy."[197]

334. Should the Board accept AEY's proposed Watson Lake bi-fuel project, UCG submitted that the associated Watson Lake study costs be rolled into capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.[198]

335. YCS recommended that all project-related costs not be allowed into rate base. YCS argued that the project is not economically prudent nor is the project environmentally prudent. YCS submitted that AEY has not made a case for how this project would help governments meet goals to eliminate or reduce the dependence on diesel in indigenous, remote and northern communities with renewable, clean energy as submitted in its GRA filing. YCS also submitted that the project would not help Watson Lake integrate any new renewable energy, but would effectively act as a "barrier to the development of renewables because of the current natural gas prices setting the predicted benchmark cost per kilowatt hour at an unrealistic and unsustainable low."[199]

336. With respect to AEY's claim that the project would result in cost savings for ratepayers, YCS described the claim as dubious and echoed Mr. Maissan's submission, stating the following:

> … the Watson Lake LNG Bi-fuel project is already marginal even with the current fossil fuel prices. Depending on the fuel source, the project is already uneconomic from one supplier. Any shift toward the historical trend (LNG and diesel closer in cost) will make this project uneconomic regardless of which supplier is liquefying and transporting the natural gas.[200]

337. Additionally, YCS submitted that the AEY analysis did not consider the impacts of renewable energy inputs onto the Watson Lake grid within the project lifetime, did not calculate how that would reduce utilization of this project and, by extension, negatively affect the economics and business case. Therefore, considering that the project is not environmentally or economically prudent, the financial risk to the ratepayer from fuel price changes, and the addition of renewable energy to the Watson Lake grid, YCS recommended that the Board deny the Watson Lake bi-fuel project.[201]

9.7.2.2 Applicant responses to interveners

338. Noting that Mr. Maissan and YCS criticized the project business case for not considering the impact of renewables, AEY submitted that it "must make decisions based on the best information it has available to it and there is no evidence of any IPP program developers proposing renewable energy projects in Watson Lake."[202] Given the restriction on nameplate capacity, AEY pointed out that it would take three separate projects to meet the limit of 2,100 MWh/year. Notwithstanding, in order to demonstrate the economic viability of the Watson Lake bi-fuel project, AEY submitted that it re-ran its

[197] JM Final Argument, page 14.
[198] UCG Final Argument, paragraph 172.
[199] YCS Final Argument, page 9.
[200] YCS Final Argument, page 4.
[201] YCS Final Argument, page 5.
[202] AEY Reply Argument, paragraph 141.

model,[203] assuming the availability of 2,100 MWh/year of renewable generation, as of January 1, 2020. AEY submitted that "… there still remains a positive NPV in all six scenarios using AltaGas pricing and three of the six scenarios using the Fortis pricing."[204] Moreover, AEY stated that there is a positive 20-year internal rate of return in all 12 scenarios. AEY added the models were predicated on only two suppliers of LNG, but it is entirely reasonable to expect additional suppliers to come on-line in the near term.

339. AEY pointed out that the current economic evaluation included in the NPVs set out in Table 2 and Table 3 of Appendix 3, and later updated in response to YUB-YECL-13(b), do not include the impact of any Yukon territorial or federal carbon tax.[205] However, should a carbon tax be imposed, AEY submitted that it would likely favour the use of natural gas for electricity generation, the effect of which would be that the NPV of the bi-fuel would increase.[206]

340. AEY submitted that there is no evidence to support any of the statements that YCS made regarding the environmental impacts or lack thereof of the Watson Lake bi-fuel project. AEY further submitted that the Yukon Environmental and Socio-economic Assessment Board heard and considered the environmental evidence in relation to this project and has approved Phase 1.

9.7.2.3 Views of the Board

341. In Board Order 2014-06, the Board stated with respect to this project:

> The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."[207] (*footnotes omitted*)

342. In Board Order 2014-06, the Board had also denied the project due to concerns regarding fair market value of certain equipment to be leased from ATCO Gas. On page 82 of that decision, the Board found that fair market value of the lease of equipment assets was best determined through a competitive tender process.

343. In this Application AEY proposed:

> … to purchase the LNG vaporization skid and LNG storage tank that was previously designed and constructed specifically for Watson Lake. This component along with the overall system design is proposed to be purchased by ATCO Electric Yukon at net book value from ATCO Gas.[208]

[203] The model is embedded in the table provided in response to UCG-AEY-53(d), Attachment 1 (Exhibit B-9).
[204] AEY Reply Argument, paragraph 144.
[205] Exhibit BB-1, Application, Appendix 3, Page 5.
[206] AEY Reply Argument, paragraph 146.
[207] Board Order 2014-06 – Appendix A: Reasons for Decision, Page 81.
[208] Exhibit BB-1, Application, Appendix 3, page 3.

344. The Board acknowledges that AEY indicated that the Watson Lake Phase 1 and Phase 2 bi-fuel projects were submitted to address the Board's concerns.

345. AEY provided the information related to a comparison of potential suppliers and fuel price forecasts, as well as alternative fuel-escalation scenarios. A compiled table of this information is below:

Table 24. **Comparison of potential suppliers and fuel price forecasts**

	Supplier	Simple Payback (years)	20-year NPV ($M)	Supplier	Simple Payback (years)	20-year NPV ($M)
Sproule price forecast	Fortis	12	0.4	Fortis	11	0.6
	AltaGas	10	2.1	AltaGas	9	2.4
Both Commodities escalate at 5%	Fortis	11	2.7	Fortis	11	3.0
	AltaGas	9	5.6	AltaGas	9	5.9
Scenario 3: both commodities escalated at 2.5%	Fortis	15	(0.9)	Fortis	15	(0.7)
	AltaGas	11	1.7	AltaGas	10	2.0
Scenario 4: diesel escalated at 5%; natural gas at 2.5%	Fortis	11	3.5	Fortis	11	3.7
	AltaGas	9	6.1	AltaGas	9	6.4
Scenario 5: diesel escalated at 2.5%; natural gas at 5%	Fortis	17	(1.7)	Fortis	16	(1.4)
	AltaGas	11	1.2	AltaGas	11	1.5
Scenario 6: both commodities doubled	Fortis	7	7.1	Fortis	6	7.4
	AltaGas	5	10.2	AltaGas	5	10.5

Source: Exhibit BB-1, Appendix 3: Table 2, Page 7; Table 3, Page 8. Source: Exhibit B-9, response to YUB-YECL-13(b), Page 3 of 6.

346. With respect to Table 24, the Board notes that of the 12 original scenarios provided by AEY, two scenarios have negative-20-year NPVs, three scenarios have NPVs below $2 million, and four scenarios have NPVs of $5 million or higher. AEY provided a further 12 scenarios wherein it accounted for the decrease in costs related to the LNG vaporizer and the LNG storage tank. The table shows that the project economics improved only marginally under the additional 12 scenarios examined.

347. Further, when AEY re-ran the model assuming a scenario of 2,100 MWh/year of renewable generation as of January 1, 2020, the generation from the bi-fuel engines was reduced. However, three (instead of two) of the six scenarios using Fortis pricing were negative.[209]

348. That being said, the Board agrees with Mr. Maissan's concern that the economic comparison provided by AEY with respect to diesel and LNG in Watson Lake must sufficiently take into account potential fluctuations in the delivery costs[210] for these fuels.

[209] AEY Reply Argument, paragraph 144.
[210] Delivery costs include the costs of liquefaction and transportation of LNG.

Mr. Maissan pointed out that the liquefaction and transportation of LNG is a higher percentage of the delivered cost than refining and transporting diesel, and he submitted that the economic evaluations must include the delivered costs of these fuels. The Board notes AEY's submission that using "delivered diesel prices based on Sproule forecast, the LNG option breaks even at an average delivered-LNG-price-to-delivered-price ratio of 75.6 percent over the lifetime of the project."[211]

349. The Board further notes that it was established on the record that the price of energy in natural gas has historically been slightly less than the cost of energy in diesel. The ratio of price of energy in natural gas to the price of energy in diesel prior to 2006 ranged from 70 to 100 percent. In 2006, this ratio dropped to about 60 percent and, more recently, it is at approximately 36.2 percent.[212] The Board agrees with Mr. Maissan that it would take only a small increase in the price ratio to make the LNG option uneconomical. In fact, AEY's data in Table 24, as well as AEY's Reply Argument, show that the project would be viable under some scenarios but not under other scenarios. While the Board understands that slightly positive or positive results are expected under some scenarios, the economic benefits of the Watson Lake project are not sufficiently supported given the outcomes of the various scenarios found in Table 24 and given the corresponding assumptions used by AEY that could impact the financial viability and resulting costs for this project.

350. Further, with respect to the Watson Lake bi-fuel project and the use of diesel units, AEY stated in its business case:

> ATCO Electric Yukon and the Independent Power Producers (IPPs) are pursuing the generation of electricity with renewable resources, however, it is almost certain that a fossil-fueled base load generation source will continue to be required in the short to medium term for reliability of the system. ATCO Electric Yukon believes the switch to a Bi-Fuel Project best accomplishes this base load generation need.[213]

351. Mr. Tenney, in testimony, confirmed that while there is development of future technologies, stand-alone bi-fuel units are not currently available other than for marine applications and that is why conversion units are proposed for this project.[214] Conversion units have not been previously utilized by AEY for utility service to Yukon customers. Conversion of the existing diesel units to bi-fuel is the only option proposed other than use of existing diesel, and in fact, conversion to bi-fuel may be the only other option currently available for the use of LNG at the Watson Lake plant. This raises the issue of whether a bi-fuel conversion should be done at this time given emerging plant technologies related to bi-fuel and LNG instead of relying on the existing diesel units at Watson Lake without bi-fuel conversion. Given the state of emerging technologies and the prospect that such technologies may affect the economic benefits associated with

[211] Exhibit B-5, JM-AEY-24(d).
[212] Exhibit B-5, JM-AEY-24(a).
[213] Exhibit BB-1, Application, Appendix 3, Watson Lake Bi-Fuel Project, Page 7.
[214] Transcript, Volume 3, page 473, lines 13 to 23, Mr. Tenney stated, "So, so far in my discussions and our group's discussions with the suppliers of these equipments, right now the bi-fuel equipment's direct from the factory without a bolt-on kit. So far they're only available in marine applications, and there's not one yet for use at a stationary power plant. So in the near term, I suspect, we're looking at bolting on the bi-fuel kit. But I suspect if it's available in marine applications, as the demand for it grows, they'll likely make it available for stationary power plants."

bi-fuel conversion, the Board finds that the approval of the project as proposed by AEY is not reasonable. Because the impact of the conversion of an individual bi-fuel unit on efficiency, the actual capital costs for conversion as well as the benefits to customers are not sufficiently known and base load generation is currently being supplied to the Watson Lake area by the existing diesel units.

352. The Board is also concerned with AEY's request that the Board approve Phase 1 of the Watson Lake bi-fuel project along with Phase 2 of the project, which will occur entirely in a future test period. Between Phase 1 and Phase 2, the total project costs are $4,695,000 for conversion of diesel units in the power plant that serves Watson Lake and surrounding area, in accordance with AEY's obligation to provide electricity to that area.

353. While the Board acknowledges AEY's position that Phase 2 would be required if Phase 1 is approved and undertaken, the Board does not consider that it is reasonable to approve the need for Phase 2 without the conversion of the unit under Phase 1 given the forecasted costs for the bi-fuel conversion project as proposed.

354. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision.

9.7.3 Old Crow Unit 3 replacement (Appendix 5)

355. AEY submitted that load growth and load duration of the community of Old Crow have steadily diminished the utilization of the 170-kW Old Crow unit due to its rated capacity. In order to address the load growth issues and ensure that there is sufficient contingency, AEY is proposing to purchase and install a new 600-kW unit to replace the existing undersized 170-kW unit. The new unit will be installed in the new building in Old Crow as it will not be able to fit in the existing building.

356. Based on the 2012 load data provided in AEY's 2013-2015 GRA, AEY submitted that the existing 170-kW unit was approved to be replaced with a 250-kW unit. Notwithstanding the Board's approval, in preparation for tender of the new unit in 2015, AEY submitted that a review of the current loading and consultation with key customers in the community took place. Based on this review and subsequent increases in connected load from 2012, a larger capacity unit (600 kW) was recommended to meet load requirements.

9.7.3.1 Views of interveners

357. Mr. Maissan submitted that the desire to have two independent and completely redundant power plants in the community of Old Crow is well beyond any planning criteria approved by the Board. Mr. Maissan went on to state that the need to have a second building is not in question, but "what is in question is the prudency of the decisions about what size generators to put into this plant which operates as an extension of the existing plant."[215] Mr. Maissan pointed out that a 400-kW generator

[215] JM Final Argument, page 9.

would be running below manufacturers' recommendation "that units are operated in the range of 50-80% of rated capacity."[216] AEY's 50-percent loading target appeared tenuous to Mr. Maissan when he noted that additional solar photovoltaic (PV) capacity is planned for Old Crow. Mr. Maissan submitted that plant efficiency will suffer as the larger generators will be very lightly loaded. In addition, Mr. Maissan submitted that a 400-kW unit could be transported into the community easier than a 600-kW unit. Moreover, considering that more solar PV capacity is planned for Old Crow, Mr. Maissan recommended that the Board reject the plan to install a 600-kW generator in Old Crow and authorize the installation of a 400-kW unit at a cost of $612,000, plus $100,000 to allow for cost increases from the previous 2014-2015 timeframe for this project.[217]

9.7.3.2 Applicant responses to interveners

358. AEY replied that, in his argument, Mr. Maissan failed to take into account the Old Crow peak loading table that clearly demonstrates the need for a 600-kW unit. AEY submitted that it would not be prudent for AEY to invest in assets such as lower-capacity units which do not meet long-term generation needs, based on the assumption that a non-dispatchable renewable resource (i.e. solar PV capacity) may potentially be installed. Furthermore, there is no evidence that the possible installation of a solar generation resource, even with a storage battery, will supply any firm capacity to be relied upon to meet the capacity needs of the community. AEY submitted that this project ensures a continued safe, reliable power source for the community.[218]

9.7.3.3 Views of the Board

359. The Board accepts the proposal as submitted by AEY. The peak loading table included in the Application[219] shows continuous growth since 2012 and the need for a higher-capacity generator. Further, as Old Crow is an isolated community, the Board accepts the submissions[220] of AEY that a full contingency backup for that community is required.

9.7.4 Destruction Bay unit replacement

360. The communities of Destruction Bay and Burwash Landing are serviced by three units located at the Destruction Bay generating plant. The Board approved AEY's request to replace two units in Board Order 2014-06 related to AEY's 2013-2015 GRA.

9.7.4.1 Destruction Bay Unit #2 replacement (Appendix 6) and Destruction Bay Unit #3 replacement (Appendix 11)

361. AEY submitted that the replacement of Destruction Bay Unit #2 was one of the units approved in Board Order 2014-06. The original scope of the project in AEY's 2013-2015 GRA was to replace the unit with a similar sized unit (300 kW). At the time of the unit tender and selection, capacity requirements were reviewed, and as a result, AEY submitted that it will tender and procure a 400-kW unit. The total cost of this project

[216] Exhibit B-5, JM-AEY-27 (b).
[217] JM Final Argument, pages 9 and 10.
[218] AEY Reply Argument, paragraphs 107 to 109.
[219] Exhibit BB-1, Application, Appendix 5, pages 1 and 2.
[220] Transcript Volume 3, starting at page 483, line12 and ending page 485, line 23.

is forecasted to be $758,000, compared to the $600,000 capital expenditure previously approved by the Board. AEY indicated that receipt of the unit and installation is scheduled to be completed in 2016.

362. AEY submitted that the replacement of Destruction Bay Unit #3 was one of the units approved in Board Order 2014-06. AEY clarified that the existing 220-kW unit was to be replaced with a larger unit (250 kW) in order to ensure that the unit would continue to operate for a reasonable amount of hours to meet load requirements.

363. AEY stated that the purchase of a new 250-kW unit was put out to tender in 2013; however, none of the bidders in the RFP process submitted bids for a 250-kW unit. Of the bids received, and after a further analysis of best fit for the power plant and community load profile, AEY selected a 312-kW unit. Receipt of the unit and installation was scheduled to be completed in 2014.The total cost of this project was $634,000, compared to the approved cost of $450,000.[221]

364. AEY explained that the actual costs "were higher mainly due to foundation issues discovered, subsequent to the initial forecast, as well as additional control work required due to the delay of the Destruction Bay PLC upgrade."[222] AEY confirmed that receipt of the unit and installation was "completed, prior to the recent installation of the increased amount of solar PV generation."[223]

9.7.4.2 Views of interveners

365. With respect to AEY's proposal to replace the two smaller units in the Destruction Bay diesel plant with larger units, Mr. Maissan pointed out that a fair bit of solar capacity has been added in Destruction Bay in recent years and significant efforts are underway to establish a wind project of 300 kW in the area. Mr. Maissan expressed concerns that AEY is opting for larger diesel generators than necessary for reasons other than efficient plant performance, and the reasons for his position include that AEY is:

> …providing themselves with a stronger negotiating position with respect to a PPA with the Kluane wind project — which AEY has been aware of for many years. The choices seems designed to frustrate or obstruct to the extent possible the installation of renewable energy in this diesel served community. The choice of 400 kW and 312 kW generators to replace generators of 300 kW and 220 kW will reduce opportunity for, and add costs to, renewable energy projects in Destruction Bay – Burwash Landing…[224]

366. Mr. Maissan recommended that the Board direct AEY to replace one of the existing smaller units with the installation of one 400-kW unit. Mr. Maissan also recommended that the Board direct the replacement of Destruction Bay Unit #3 (CUL 230 220 kW unit) with a unit no larger than 250 kW. AEY should be directed to provide the 2015 load duration curves for Destruction Bay plant in its compliance filing. Mr. Maissan recommended:

[221] Exhibit BB-1, Application, Appendix 11, page 1.
[222] Exhibit BB-1, Application, Appendix 11, page 1.
[223] Exhibit B-5, JM-AEY-27 (a).
[224] JM Final Argument, page 15.

> … that the Board order AEY, in negotiations for an IPP with the proponents of the Kluane wind project [sic] to allow diesel displacement down to a load level to the lowest normal 2015 dispatch level without penalty or cost to the proponent.[225]

9.7.4.3 Applicant response to interveners

367. AEY pointed out that the two Destruction Bay unit replacement projects were scheduled — and in the case of Unit #3 replacement, completed — prior to the recent installation of solar PV generation in the Destruction Bay and Burwash communities. AEY acknowledged that the Burwash Landing wind project may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid. However, AEY submitted that:

> … it is not prudent or common practice for a utility to reduce the installed capacity of its generation facilities as a result of the possible installation of a non-dispatchable renewable resource, regardless of whether it is owned and operated by a third party or the utility itself.[226]

368. With respect to determining the size of Destruction Bay Unit #2, AEY considered the capacity as well as operational efficiency requirements. AEY submitted that replacement of Unit #2 with a new unit of the same size (300 kW) would not have allowed AEY to meet operational efficiency requirements, as units would have been under or overloaded during automated dispatch. AEY added:

> … at the current dispatch level there are times in which Unit 2 is operated at an overload condition in respect to its prime rating. The only solutions to this overload issue are to de-rate the unit or replace it with a larger unit. If the de-rate option was selected, it would negatively impact the operation of Unit 1, forcing it to run in a low loading mode. Selecting a larger unit allows Unit 2 and Unit 1 to be dispatched in a more efficient manner.[227]

369. AEY submitted that contrary to Mr. Maissan's assertions, the sizing considerations were done to meet firm capacity requirements and to allow for an efficient dispatch of the units, all of which are in line with AEY's obligation to serve customers with safe and reliable electricity.

9.7.4.4 Views of the Board

370. Destruction Bay Unit #3 was approved in AEY's 2013-2015 GRA. The unit was substantially completed and operational in 2014, with final acceptance in 2015. Further, the Board notes that Unit #3 replacement was completed prior to the recent installation of solar PV generation in Destruction Bay and Burwash Landing.

371. AEY determined through the tender process that the best fit for the power plant and community load profile was a 312-kW unit rather than the originally forecast capacity of 250 kW. The final cost of the project was $184,000 over the GRA-approved forecast. AEY indicated that the variance between the actual and forecast costs was

[225] JM Final Argument, page 15.
[226] AEY Reply Argument, paragraph 112.
[227] AEY Reply Argument, paragraph 117.

due to foundation issues discovered subsequent to the initial forecast and additional control work. AEY added that movement to the larger generator capacity would increase operational hours of the unit and concomitantly increase the units' efficiency.[228]

372. The Board finds the reasons provided by AEY — operational efficiency, community and load profile[229] — support the need for the larger capacity unit. In addition, the cost for the larger unit and the need to mitigate the foundation issues identified are acceptable reasons for the cost variance. The Board approves the costs as filed. Although wind capacity may eventually be a source of renewable energy on the Destruction Bay/Burwash micro-grid, the Board accepts AEY's submission that wind generation will not contribute to firm capacity requirements within the test period.

373. With respect to Unit #2, the Board notes AEY's submission that replacement of this unit with a similar-sized unit would not have allowed AEY to meet the Operational Efficiency Requirements, as units in the generation plant would have been under or overloaded during automated dispatch. Therefore, the Board approves the additional costs associated with the larger 400-kW unit.

374. Considering the above, the Board approves AEY's replacement of Destruction Bay Units #2 and #3, as filed.

9.7.5 McIntyre subdivision rebuild (Appendix 8)

375. The McIntyre subdivision rebuild is a multi-phase project to replace the existing end-of-life underground electrical infrastructure serving the McIntyre subdivision in the City of Whitehorse. The original forecast for Stage 1 was approved as part of AEY's 2013-2015 GRA in Board Order 2014-06.

376. AEY referred to this project as being a complex "brownfield" infrastructure replacement. The original underground electrical system serving the subdivision is operating at 35 kV and was installed circa 1977. The proposed project will convert the subdivision's operating voltage to the standard 25-kV system. AEY indicated that 25-kV equipment is standard in Whitehorse's distribution system and provides improved electrical performance for residential customers.

377. The original scope of the project was to install a new 25-kV underground electrical system in close proximity to the existing 35-kV system. As Stage 1 was underway, AEY discovered that the location of the existing underground system would be in constant conflict with the installation of the new system. This made the field construction more time-consuming. Time constraints imposed on construction permits from the Kwanlin Dun First Nation (KDFN) made it necessary that a new project scope be developed. AEY explained the change in project scope due to installation issues:

> The new project scope involved the installation of a temporary overhead shadow electrical system which would allow construction crews to install the new underground system with the old underground system safely deenergized. This would allow the construction crews to work at a similar pace to a

[228] Exhibit BB-1, Application, Appendix 11, page 2.
[229] Exhibit BB-1, Application, Attachment 11.4, page 1.

> Greenfield project. The work would also include the installation of low voltage pedestals to connect to the overhead system and a new main underground feed to the subdivision.[230]

378. The following table shows approved costs, AEY's actual costs, and its forecast costs for the McIntyre subdivision replacement project:

Table 25. **McIntyre subdivision rebuild — 2013 to 2020 — actual (A) and forecast (F) costs ($000s)**

Year	Actual/Forecast	Streetlights	Total	Scope
2013 (A)	656	-	656	Temporary overhead
2014 (A)	418	-	418	Low voltage pedestals, connected to feeds
2015 (A)	379	-	379	Main underground feed to the subdivision
2016 (F)	565	175	740	Hanna and McCandless
2017 (F)	930	256	1,186	Murphy (partial), O'Brien, and McCrimmon
2018 (F)	500	100	600	McClimon
2019 (F)	600	150	750	Complete Murphy, McIntyre up to McCauly
2020 (F)	300	100	400	McCauly to Hamilton to McIntyre
Total	**4,348**	**781**	**5,129**	

Source: Exhibit BB-1, Application, Appendix 8, Table 1, Page 3.

379. In a letter[231] dated October 24, 2016, AEY submitted that it is seeking Board direction as to the appropriate treatment of the potential cost savings, should the KDFN accept one of the alternatives such as "Alternative 2" in the business case provided in Appendix 8 of the Application. The business case included the following:

> Alternative 2: Explore the benefits of utilizing some of the overhead system in coordination with some of the new underground electrical infrastructure. This would result in a hybrid system as it would be a combination of overhead and underground. This alternative would require the approval of the KDFN.[232]

380. AEY submitted that it is anticipated that "Alternative 2" would alter the work required and result in a potential cost savings in 2018-2020, which is outside of the test years. AEY clarified that it is requesting the Board to provide direction as to whether or not the expected costs savings could be applied as an offset to the contribution required by the KDFN in the future.

9.7.5.1 Views of the Board

381. The Board notes that interveners did not comment on AEY's request.

382. During the hearing, the Board notes AEY's submission that it had extensive meetings with KDFN. AEY submitted, "It's very clear that they want to have an underground power system when we're done in there… that's what they would like to have when we leave that subdivision at the end of the project."[233] Moreover, the Board

[230] Exhibit BB-1, Application, Attachment 11.4, page 1.
[231] Exhibit B-13, YECL letter to YUB re corrections, updates and clarifications, October 24, 2016.
[232] Exhibit BB-1, Application, Appendix 8, McIntyre Subdivision Rebuild, page 3.
[233] Transcript, Volume 1, page 151, lines 1 to 5.

notes AEY submission that "… there was an original customer contribution when the original system went in back in the '70s, so we wouldn't be asking the customer to recontribute."[234]

383. The Board notes that the ultimate scope of the project has not been determined by AEY at this time. AEY submitted two project alternatives: (1) an underground system, or (2) a hybrid system (combination of overhead and underground).

384. The Board accepts AEY's test-period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA.

385. If AEY's proposal for "Alternative 2" (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings.

386. The Board will provide further direction in the next GRA regarding AEY's request as to whether or not the expected cost savings could be applied as an offset to the contribution required by the KDFN.

9.7.6 Significant capital projects

387. In Board Order 2009-2, the Board directed "YECL to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests."[235] In Attachments 9.1 and 9.2 of the Application, AEY provided a listing of capital expenditures for 2016-2017, which included project descriptions for projects greater than $100,000. AEY also provided business cases for all major capital projects ($500,000 or greater) in Appendix 1 to Appendix 11 of the Application.[236]

388. UCG noted the Board's consideration in its January 2007 Report to the Commissioner in Executive Council re YEC's 20-year resource plan[237] that given the smaller rate base in the Yukon and the small number of ratepayers in the Yukon, a $1-million threshold would be appropriate for capital expenditures to be reviewed by the Board pursuant to Part 3 of the *Public Utilities Act.*

389. Considering the above, UCG recommended that the following projects should be reviewed pursuant to Part 3 of the *Public Utilities Act:*

(a) McIntyre subdivision rebuild;[238]

(b) Watson Lake bi-fuel projects;[239]

(c) Watson Lake Unit #2 replacement;[240]

[234] Transcript, Volume 1, page 152, lines 5 to 8.
[235] Board Order 2009-2, Appendix A: Reasons for Decision, page 37.
[236] Exhibit BB-1, Application, page 9-5.
[237] Yukon Utilities Board Recommendations YEC 20-Year Resource Plan: 2006-2025, Page 28, issued January 15, 2007.
[238] UCG Final Argument, paragraph 187.
[239] UCG Final Argument, paragraph 192.
[240] UCG Final Argument, paragraph 197.

(d) Downtown Whitehorse capacity improvement project;[241]

(e) Old Crow Unit #3 replacement;[242]

(f) Whistle Bend Subdivision Stage 3-C project;[243]and

(g) Fish Lake Ditch #3 diversion replacement project.[244]

9.7.6.1 Views of the Board

390. With respect to UCG's submission that the above-mentioned projects be reviewed pursuant to Part 3 of the *Public Utilities Act,* the Board considers that this request is premature because neither application has been made to the minister under section 39 of the *Public Utilities Act*, nor has the minister designated any of the projects as a regulated project under section 37 of the *Public Utilities Act*. Moreover, the Board does not determine that projects are Part 3 projects under the *Public Utilities Act*, but makes recommendations on energy projects only when the minister refers them to the Board. Accordingly, the Board finds that UCG's recommendations on Part 3 projects and associated capital expenditures do not apply.

10 Income tax

391. In its Application, AEY continued to use the flow-through method for calculating income tax expense. This method was approved by the Board in Board Order 2014-06. AEY argued that since the use of the flow-through method was not raised as an issue by any party during the testing of its Application, the Board should continue to approve the use of this method.

10.1 Views of the Board

392. The Board agrees with AEY that there is no reason to change the currently approved flow-through income tax method used by AEY in its Application. AEY's method of determining income tax expense to be recovered through rates is approved as filed.

11 Previous Board directions

393. AEY provided the following responses to prior Board directions from Appendix A: Reasons for Decision from Board Order 2014-06:

Board Direction	AEY Response	Board Comment
Direction 8, Page 51. The Board agrees with the submissions of UCG that no assessment has been provided	*Application, page 11-1,* ATCO Electric Yukon has engaged Concentric Energy Advisors Ltd. to undertake an	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No

[241] UCG Final Argument, paragraph 202.
[242] UCG Final Argument, paragraph 207.
[243] UCG Final Argument, paragraph 212.
[244] UCG Final Argument, paragraph 217.

within this proceeding regarding the comparability of YECL to the BCUC benchmark utility Fortis Energy. The previous risk premium was based on FortisBC, which is an electrical distribution company. BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear. The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.	analysis as to whether a risk premium over the BCUC GCOC benchmark utility is appropriate and if so, the quantum of such premium. Their analysis is contained in Attachment 8.1 included in section 8 of this Application.	further response is required.
Direction 12, page 62. The Board understands that YECL needs to explore alternatives respecting the use of wind to generate power in the area of Burwash and Destruction Bay, which interveners have been promoting. Accordingly, the Board finds the study costs warranted and reasonable. In addition, the Board directs YECL in its next GRA to provide results of the feasibility study.	*Application, page11-2.* ATCO Electric Yukon contributed funds ($20,000) towards this initiative in 2013 and received a report titled "Burwash Landing and Destruction Bay Wind-Diesel Prefeasibility Update." ATCO Electric Yukon filed this report in response to Undertaking 17 during the 2013-2015 GRA hearing. Since that time ATCO Electric Yukon has received one further update in early 2014 but ATCO Electric Yukon is no longer engaged in this project and no further contributions have been made to this project, as such, ATCO Electric Yukon is not expecting to receive any further reports arising from this initiative.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

Direction 13, page 64. YECL needs to provide information in relation to project costs overruns in its Application. Therefore, the Board directs YECL in future applications to explain more fully the reasons for project overruns. For clarity, for project costs overruns that are (collectively) 100-percent over and $100,000 greater than the original estimate, YECL is to provide business case type descriptions in the Application, to alert interveners and the Board to the cost overruns, thereby allowing for a more efficient process to examine the cost overruns. Furthermore, YECL, in their explanations, are to explain why the nine expenditures were not foreseen and actions it takes to ensure that such overruns will not occur in future. Moreover, for projects similar in nature to the Oracle HRxcellence HR management project with expenditures greater than $100,000, which may arise between GRAs, YECL, in future applications, is directed to furnish business cases for such projects and the reasons why YECL deemed it necessary and reasonable to proceed with the project.	*Application, page 11-3 to 11-4.* ATCO Electric Yukon has included project completion summaries for all projects listed below that were forecast in the 2013-2015 GRA where actual costs were 100 percent and $100,000 greater than the original forecast. In addition, ATCO Electric Yukon has included a project completion summary for the Fish Lake Dyke Upgrade to explain the variance in actual costs to forecast for that project. Business cases have also been provided for completed projects where the actual costs were in excess of $100,000 and for which no business case was provided in the 2013-2015 GRA. ATCO Electric Yukon has included business cases for the completed projects listed below in Attachments 11.7 through Attachment 11.13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 14, page 70. The Board rejects UCG's recommendation because it is the actual amounts spent on projects that are added to rate base. The Board therefore approves other small project costs. That being said, the Board notes YECL's submission that expenditures "forecast as Other Projects are subsequently able to be broken down into greater detail when actual amounts are reported. Looking only at the variance for Other Projects does not provide an accurate picture of variance in the actual amounts spent for capital additions as compared to the forecast." Bearing this in mind, in	*Application, page 11-5.* In section 9, Schedule 9.2 of this Application, ATCO Electric Yukon has provided a detailed listing of all projects completed and actual amounts spent by project from 2013 through 2015. ATCO Electric Yukon has continued to group various projects in the "Other projects less than $20,000" category in Schedule 9.2, and submits this approach is appropriate considering the aggregate totals in this category are under the threshold of $100,000 highlighted in Direction 13.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.

order to help the Board and interveners examine more efficiently and process an application, the Board directs YECL, in future GRAs, to indicate in their applications how the approved forecast Other Projects amounts are subsequently spent.		
Direction 15, page 71. The Board accepts, based on the evidence, that the expenditures were reasonable and prudent in the circumstances. The Board rejects UCG's recommendations because the business case was not required for each related component and seeing the Board's finding of prudency. However, in future GRAs, the Board directs YECL to provide business cases for completed related projects which may span multiple years and total more than $500,000.	*Application, page 11-6.* On Schedule 9.2 of the Application, ATCO Electric Yukon has included the reference to where the business cases can be found in either the 2013-2015 GRA or in Appendix 1-11 of this Application. Business cases have been provided for all projects that span multiple years where costs were expected to be greater than $500,000.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response is required.
Direction 20, page 101. As argued by CW and UCG, the Board recognizes that the forecast risks with respect to the DSM program are one-sided. If participation rates are lower than expected, the utilities benefit, but if participation rates are higher than expected, the utilities have the ability to enforce the budget. Therefore, in the Board's view, a deferral account would not only protect ratepayers but it would also normalize the incentive for the utilities to maximize participation in the DSM program. Accordingly, the Board orders YECL to track all DSM programming costs occurring in 2014 and 2015 in a deferral account and to apply for recovery of those costs in its next GRA. Further, the Board affirms it does not approve the program for the five-year term requested and that the utilities are to make a formal application to the Board before expanding the DSM program elements beyond that approved above or beyond 2015. The Board directs YECL, within its compliance	*Application, page 11-7.* The DSM programming costs approved in Board Order 2014-06 for the 2014 and 2015 test period have been tracked as directed in deferred charges. ATCO Electric Yukon was unable to complete the program as originally designed and spend all of the approved DSM program costs in 2014 and 2015 period; therefore the remaining approved amount will be spent in 2016. ATCO Electric confirms that it has not changed the scope of the approved DSM program. In this Application, ATCO Electric Yukon is applying for recovery of these previously approved costs (incurred from 2014 through 2016) over the next five years in a manner consistent with the previously approved DSM costs.	Upon review of the Application and AEY's explanation, the Board finds that AEY has complied with the direction. No further response required.

filing, to quantitatively provide the load reduction in GW.h related to DSM for each of the years 2014 and 2015, by rate class that has been incorporated in YECL's load forecast and to explain and quantify the changes to the load forecast based on the determinations of the Board regarding DSM.		

12 Deferral accounts

394. In its Application, AEY proposed deferral-account treatment for three new cost categories, while maintaining deferral treatment for those categories previously approved by the Board. AEY's summary of existing and proposed deferral accounts is shown in the following table:

Table 26. **Summary of existing and proposed deferral accounts**

Name of existing or proposed deferral account	Existing	Proposed
Rate case costs	X	
Defined benefit pension plan	X	
Feasibility study or program: DSM program (approved program) Watson Lake LNG — phase I (approved study) Renewables study (proposed study) Joint grid study (proposed study)	X	
Purchase power flow-through	X	
Diesel fuel	X	
LNG fuel		X
Board order or changes in legislative provisions		X
Statutory Federal and Territorial income tax rates		X

Source: Summarized from Application

395. The Board has considered the five existing deferral accounts and finds that their respective intent and scope have not changed. AEY's existing deferral accounts continue to be approved.

396. In the following sections, the Board will discuss the three new deferral account categories proposed in AEY's Application and whether they should receive deferral-account treatment.

12.1 LNG Fuel Deferral

397. Please refer to the section 4.5 of this decision.

12.2 Board Orders or Changes in Legislative Provisions Deferral

398. In its Application, AEY sought the ability to flow through, dollar for dollar, costs related to Board Orders or legislative provisions resulting in changes to the rules or parameters that AEY operates under for the 2016-2017 test period.

399. The IPP Policy for Standard Offer Prices was cited as one example in support for this deferral account.

400. In argument, AEY claimed that in future, there is no guarantee of stakeholder input or significant lead time. AEY added that it has no control over these policies or programs and has no way to forecast with certainty the impact related to these types of programs, and therefore seeks deferral account treatment.[245]In reply, AEY challenged the assertions of Mr. Maissan about the micro-generation program, stating that the response to JM-AEY-5(c-d)[246] did not include the full costs incurred by AEY (such as administrative costs), adding that there is no certainty of that program continuing to operate in its current manner.[247]

401. AEY did agree with Mr. Maissan in that it is a stakeholder in relation to the development of the IPP program. However, AEY countered that it does not control the actual implementation of the program and that it would be at risk for any changes until its next GRA.[248]

12.2.1 Views of interveners

402. John Maissan did not support the AEY request for a Board Orders or Changes in Legislative Provisions Deferral Account. Mr. Maissan noted that the micro-generation program provided net benefits to AEY. In regard to the IPP program, AEY has been an active participant along with the Yukon government, Yukon Development Corporation (YDC) and YEC .

403. The effects of the commercial energy incentive program run by the Yukon government were another reason cited by AEY for this deferral account. Mr. Maissan argued that the effects of this program are captured within AEY's load-forecasting process, and thus had minimal impact.[249]

404. UCG stated that a deferral account to track costs related to Board Orders or legislative provisions does not provide AEY with the ability to flow costs through, dollar for dollar, to ratepayers. A deferral account simply tracks costs for review and possible recovery at a later time.[250]

12.2.2 Views of the Board

405. In AEY's 2013-2015 GRA, AEY requested a deferral account to flow through, dollar for dollar, to the tariff any costs related to Board Orders or legislative provisions

[245] AEY Final Argument, paragraphs 11-12.
[246] Exhibit B-5 — YECL Responses to Maissan Requests
[247] AEY Reply Argument, paragraph 13.
[248] AEY Reply Argument, paragraph 14.
[249] JM Final Argument, page 1.
[250] UCG Reply Argument, paragraph 13.

resulting in changes to the rules or parameters that AEY operates under or that bear on the nature and extent of AEY's obligations as a regulated utility and which impact its 2013 to 2015 revenues or revenue requirement.[251]

406. In Board Order 2014-06, the Board ruled that:

> … on most occasions that the Board has witnessed, legislative change involves extensive stakeholder input and significant lead time before the change is implemented… The Board finds that YECL would have sufficient time to incorporate any such changes at the time of any GRA filing. Therefore the Board rejects YECL's request for this deferral account.[252]

407. The Board's views have not changed. The evidence in this proceeding is that AEY has been able to actively participate in potential legislative changes respecting the implementation of new programs, so AEY has not shown the need for such a deferral account. The Board notes Mr. Maissan's comments about little or no impacts of the programs referred to by AEY. The Board denies AEY's request for a Board Orders or Legislative Provisions Deferral Account.

12.3 Statutory Federal and Territorial Income Tax Rates Deferral

408. In its Application, AEY requested deferral-account treatment for income tax beginning in the year 2016. The deferral amounts would be based on any deviance from enacted federal and territorial statutory rates, which were each currently set at 15 percent. AEY submitted that any changes from these rates would be used to determine an updated revenue requirement that, when compared to final approved revenue requirement, would initiate either a refund to or collection from customers for the difference.

409. AEY cited uncertainty with respect to global economics and recent federal government changes as increasing the possibility of significant tax changes between GRAs. During the hearing, AEY witness James Grattan indicated a further potential for changes to the territorial statutory rate depending on the outcome of the territorial election.

410. In argument, AEY summarized:

(a) Changes in statutory tax rates can be material;

(b) Given that the statutory rates are set by the Territorial and Federal Governments and these rates are not published in advance of annual budgets, there is uncertainty regarding forecast accuracy;

(c) The statutory rates are determined by the Territorial and Federal Governments, and tare [sic] therefore beyond AEY's control; and

[251] Board Order 2014-06 – Appendix A: Reasons for Decision, page 1.
[252] Board Order 2014-06 – Appendix A: Reasons for Decision, page 103.

(d) AEY is not typically at risk with respect to items that are beyond its control and that are material.[253]

12.3.1 Views of the Board

411. The Board considers that the need for a deferral account has not been shown given the two-year test period. Further, the criterion for a deferral account is that AEY is typically at risk with respect to items that are beyond its control and that are material. In the Board's view, AEY has not shown that it is at risk or that any risks are material from changes in federal or territorial income tax rates. For these reasons, the Board denies AEY's request for a deferral account for statutory federal and territorial income tax rates.

12.4 Deferred Charges and Credits

412. For those account categories currently approved for deferral-account treatment, AEY monitors charge and credit transactions.[254] Generally, AEY will incur the deferral-account related expenditures over time and will subsequently recover the approved costs through deferral account revenue requirement. This is currently the treatment ascribed to hearing costs and deferred pension costs, each of which were forecasted to be recovered in revenue requirement evenly over the years 2016 and 2017.

413. In its Application, AEY proposed similar treatment for the tracking and recovery of costs related to feasibility or other studies, such as those pertaining to Watson Lake, Renewables and Alternative Energy, and a Joint Smart Grid. In some cases, after the study was completed, AEY proposed to recover the study costs within its deferral accounts over a period of two years. In the alternative, and as is the case with the deferred DSM program costs, AEY proposed to capitalize the costs into rate base and amortize them over a specified period of time.

414. UCG provided a general comment that, "All deferred study costs should be removed from rate base and either amortized (if prudent) outside of rate base or rolled into a related capital asset."[255]

415. UCG submitted that study costs do not meet the "used or required to be used" test for consideration as a utility asset providing utility service to customers, despite that the costs may have been incurred prudently.[256]

416. Interveners raised other concerns with respect to AEY's proposed recovery of these study-related costs, each of which are discussed in the four sections that follow.

12.4.1 Demand Side Management (DSM) Program Study Deferral Account

417. AEY proposed[257] to move costs related to the approved DSM program study out of the deferral account and into rate base. Notwithstanding an issue related to the use of the mid-year convention for depreciation purposes addressed elsewhere in this

[253] AEY Final Argument, paragraph 164.
[254] Exhibit BB-1A AEY GRA Schedules, schedule S8.8.
[255] UCG Final Argument, paragraph 30.
[256] UCG Final Argument, paragraphs 166-174.
[257] AEY Final Argument, paragraphs 115-118.

decision, AEY stated that the use of a five-year amortization period (2014-2018) for cost recovery was consistent with the Board's direction in section 12.1 of Board Order 2014-06.

418. AEY stated that evidence of prudent expenditures related to the DSM program was provided in interim evaluation reports and these reports concluded that the DSM programs were well-received by Yukoners, were cost-effective, and that participation met or exceeded most KPIs.

419. In response to UCG's recommendation that deferred study costs should be removed from rate base, and either amortized outside of rate base or rolled into a related capital asset, AEY stated that the DSM program study costs in this case were for programs previously approved by the Board.

12.4.1.1 Views of interveners

420. UCG[258] questioned why the deferred DSM program costs would subsequently be treated as a capital item and attract carrying costs like other assets placed into rate base. UCG submitted that AEY was entitled only to the return of, and not a return on, prudently incurred DSM costs.

421. YEC[259] disagreed with UCG's suggestion that the DSM study costs should not be treated as capital assets earning a return on the same basis as other rate base elements. YEC submitted that UCG's recommendation should be disregarded by the Board.

12.4.1.2 Views of the Board

422. The Board can find no basis to consider UCG's recommendation that AEY was entitled only to the return of, and not return on, the DSM program study costs. AEY's treatment of these costs — by way of capitalization into rate base, and the attendant calculations of depreciation and return — is consistent with the Board's direction in section 12.1 of Board Order 2014-06. For this reason, the Board does not accept the recommendation made by UCG. The Board approves the transfer of the DSM program study costs out of the deferral account and into rate base to be amortized over a period of five years, as proposed by AEY.

12.4.2 Watson Lake LNG Study Deferral Account

423. In its Application, AEY requested approval for $494,000 in study and development costs related to the Watson Lake bi-fuel project. AEY proposed to recover these forecast costs evenly over the 2016-2017 test period through the study's associated deferral account. AEY submitted that the study costs were incurred prudently and should be recovered from customers whether or not any of the Watson Lake bi-fuel project capital costs are approved.[260]

[258] UCG Final Argument, paragraph 228,.
[259] Yukon Energy Reply Argument, pages 9-10.
[260] AEY Final Argument, paragraphs 105-108.

424. As an alternative, AEY stated that it was not opposed to capitalization of the study costs, should the Watson Lake project be approved, with subsequent cost recovery over the lifetime of the related assets.[261]

12.4.2.1 Views of interveners

425. UCG argued that in Board Order 2013-01, the Board determined that feasibility expenditures associated with projects deemed to be feasible should remain in "Work in Progress" until such time that the project is set aside or the utility comes before the Board for a prudence review. In Board Order 2014-06, the Board determined that Watson Lake bi-fuel project study costs would be held in "Work in Progress" until such time as the project may be completed.

426. UCG submitted that if the Board accepts the proposed Watson Lake bi-fuel project proposed by AEY, then $494,000 in Watson Lake Study costs should be rolled into the capital costs of that project and recovered over the life of the Watson Lake bi-fuel project.

427. Consistent with his views that the Watson Lake bi-fuel project itself be denied by the Board, Mr. Maissan recommended that all actual study costs expended to date should be amortized over a five-year period.[262]

12.4.2.2 Views of the Board

428. The Board does not consider that adding complexity with respect to the recovery of the Watson Lake LNG study costs is necessary. To recover the study costs over the life of the Watson Lake bi-fuel project, as was recommended by UCG, would require an allocation of the study costs to several individual account numbers, each with a unique service life. The Board has determined doing so would not result in an efficient or straightforward process of cost recovery and would be unduly onerous. Further, since in section 9.7.2 of this Order the Board has rejected the Watson Lake bi-fuel project, this issue of rolling the study costs into the capital costs is moot. For these reasons, UCG's recommendation is denied.

429. The Board accepts Mr. Maissan's recommendation that recovery of the Watson Lake study costs and development costs forecast in the amount of $494,000 should be on the basis of an amortization period of five years. This period of time is consistent with that used for the recovery of the DSM program study costs. The Board finds this to be a reasonable approach for the recovery of the Watson Lake bi-fuel study costs.

12.4.3 Renewable and Alternative Energy Feasibility Study Deferral Account

430. AEY proposes to include $300,000 in 2016 and $200,000 in 2017 as charges related to work it has planned regarding the Renewable and Alternative Energy Feasibility study.[263] The $500,000 in costs for the study would be recovered through AEY's deferral account in the amount of $150,000 in 2016 and $350,000 in 2017.

[261] AEY Final Argument, paragraph 108..
[262] JM Final Argument, page 15.
[263] Also referred to in AEY's application as the "Renewables Feasibility Study"; Exhibit BB-1, page 8-8 and Schedule 8.8.

431. AEY proposed to assess individual communities and retain third party expertise to carry out the studies through a combination of competitive processes and "sole-sourcing."[264] The studies are intended to identify the optimal size and configuration of company-built, -owned and -operated renewable and alternative energy generation in each of the five isolated communities served by AEY which currently rely on diesel power generation. The studies will also assess energy storage systems and potential improvement for energy efficiency through waste-heat recovery opportunities in each of the communities.

432. Once the studies are complete, AEY proposed that any technically and economically feasible projects identified therein would be brought forward as business cases in stand-alone proceedings for approval by the Board. This would ensure customers receive more immediate benefit of the studies and resulting projects, without the need to wait for a subsequent GRA.

433. Further, AEY indicated its commitment that, subject to any confidential or proprietary information contained in the renewable energy studies, they would be prepared to share the study publicly in connection with any resulting application or earlier in an appropriate forum, such as the utility's website.

434. During the oral hearing, AEY witnesses confirmed that preparation of the renewables study was behind schedule and that no work had been completed at that time.[265]

435. In response to UCG's recommendation that deferred study costs should be removed from rate base and either amortized outside of rate base or rolled into a related capital asset, AEY stated with respect to feasibility studies, such as the one proposed for renewables, deferral treatment for approved expenditures is appropriate given that such studies may not result in the construction of a project, or a near-term project.[266]

12.4.3.1 Views of interveners

436. Given that AEY had not commenced development of its proposed renewables study, Mr. Maissan argued it was unreasonable to expect that AEY could incur the entirety of its proposed expenditures in a prudent manner subsequent to a Board Order.

437. Mr. Maissan also took issue with AEY development of company-owned renewable and alternative energy sources, stating that such projects would be in direct competition with IPP proponents. Mr. Maissan viewed it to be inappropriate for ratepayers to fund AEY to, in essence, compete with the private sector, which is funded privately.

438. As an alternative to the Board approving a $500,000 renewables study, Mr. Maissan recommended that the Board should approve (1) study costs of up to $150,000 "to prepare for the significant displacement of diesel generation in Destruction

[264] AEY Final Argument, paragraph 110..
[265] Transcript, Volume 2, page 292.
[266] AEY Reply Argument, paragraphs 88-90..

Bay – Burwash Landing, Old Crow, and Watson Lake using renewable energy sources, including wind and solar PV", and (2) study costs of $50,000 "for a study on how to improve the fuel efficiency of AEY's diesel plants, including the utilization of residual heat, that applies to all of AEY's diesel plants."[267]

439. With respect to each of his proposed studies, Mr. Maissan made further recommendation that the Board order AEY to submit detailed terms of reference, submit study reports upon their completion, and also seek Board approval before the implementation of any action arising out of the study findings.

440. YCS expressed similar views to that of Mr. Maissan in that the concept of the renewables study as pursuing a replacement for diesel fuel was flawed and should be denied by the Board. YCS stated that if ratepayers were being asked to pay for the study, then it must be shared as soon as completed and not withheld from viewing until the next GRA.[268]

441. YEC[269] discounted Mr. Maissan's argument that AEY developing renewable and alternative energy sources would be in competition with IPP proponents. YEC stated there was no basis for Board to restrict prudently incurred expenditures related to studies assessing renewable generation options.

442. YEC also addressed comments from Mr. Maissan and YCS requesting the sharing of any renewable study results prior to AEY's next GRA, stating that there is no mandate for the Board to address such proposals. YEC expressed similar views with respect to AEY's proposal to bring forward any business cases stemming from the renewables study in a stand-alone proceeding before the Board without waiting for a subsequent GRA.

12.4.3.2 Views of the Board

443. In this test period, AEY has requested various studies for Board approval to include amounts for studies in rates. The Board considers that such studies are best conducted by industry or funded by government initiatives.

444. In addition, the Board understands that it may be difficult for the utility look to government grants or other sources of funding through customer rates without a fully formulated proposal for a renewable or alternate energy project. This was explained by Mr. Tenney in his testimony:

> Q. Are you aware, gentlemen, at this time of any further funding opportunities for projects stemming from the renewable study from either the Federal or Territorial Governments that may be known to you or have been — become public since you filed your application and your IRs?
>
> A. MR. TENNEY: Again, in one of the information responses, we did talk about the last — the 2016 federal budget that they earmarked, I believe it was $10.6

[267] JM Final Argument, page 12.
[268] YCS Final Argument, page 9.
[269] YEC Reply Argument, pages 7-9.

> million for renewable energy programs. We have been working with the Federal Government to see if we can access that.
>
> To date, the message — and I think we — in one of that - October 24th, I believe it was, update that we did, we had originally said that we hadn't included the watt — we weren't seeking federal funding for the Watson Lake bi-fuel project, but we did through the Canadian Electrical Association. The ATCO Group of Companies was participating with them and did submit that project in looking for funding.
>
> What we got back — what I understand we got back from the Federal Government is right now they were looking for projects that were farther along. In fact, they were looking for projects that were shovel ready. So they weren't looking to fund more feasibility studies. They were looking to help make the project — the economics work to get it under construction.
>
> So, to date, we haven't found any funding, but that doesn't mean we're not going to continue to try and access some.[270]

445. The Board is of the view that studies proposed in the Application would reasonably involve an assessment of need, feasibility and policy objectives that could involve government, academics, YEC, municipalities, customers or other stakeholders.

446. The legislative scheme is intended to provide for the regulation of utilities and to provide the Board with various responsibilities in the public interest, including the setting of rates of the utility in the provision of electricity to customers in the Yukon.

447. There is not sufficient evidence for the Board to approve the Renewable and Alternative Energy Feasibility Study proposed in the Application and, without further information, the Board is unable to assess whether or not these studies should be conducted given the need or feasibility of a study to support a renewable and alternative energy project or projects, and whether proposed costs for these studies should be recovered in customer rates. The Board considers that information that should be provided in support for these types of studies or initiatives would include, but is not limited to:

- An analysis of how the study or initiative proposed is related to the utility's statutory requirements of provision of utility service pursuant to the *Public Utilities Act* and its regulations;
- The drivers, need and feasibility for the study or initiative;
- The scope of the study or initiative;
- An expected budget for studies, preliminary reports, and any other primary or secondary reports, as well as a budget for any known implementation costs or an estimate of any expected implementation costs;

[270] Transcript, Volume 3, page 453, lines 11 to 25 and 454 lines 1-15.

- The specific utility projects that are expected to be reviewed or impacted by the proposed initiative(s), as well as corresponding benefits to customers expected as a result of the study and initiative(s); and

- Whether cost-recovery studies and alternative-energy initiatives, energy-saving initiatives, or other initiatives have been explored through grants or other sources of funding, including shareholder funding.

448. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility Study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision.[271]

449. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference, or filing any completed Renewable and Alternative Energy Feasibility Study.

450. Further to the request for two alternative studies as proposed by Mr. Maissan in argument, the Board finds the feasibility and the costs for AEY to undertake these studies has not been examined by the utility or the Board through a proceeding. These recommendations have not received the benefit of being tested by parties during the course of this proceeding. For these reasons, the Board does not support Mr. Maissan's request for AEY to undertake two alternative studies.

12.4.4 Joint Smart Grid Study Deferral Account

451. AEY requested approval for costs related to a Joint Smart Grid Study anticipated to be undertaken in 2017 in partnership with YEC at a cost of $100,000. The study is intended to assess the potential fit and viability of a smart grid in the Yukon. AEY advised that it intends to have the completed smart grid study filed with the Board and made public.[272]

12.4.4.1 Views of interveners

452. Mr. Maissan supported the Board's approval of the $100,000 budget for the proposed smart grid study, citing that there could be significant benefits to ratepayers in the long term if the utilities were to embrace a smart grid approach in the Yukon.[273]

12.4.4.2 Views of the Board

453. The Board considers that such studies are best conducted by industry or funded by government initiatives.

454. There is not sufficient evidence for the Board to approve the Joint Smart Grid Study proposed in the Application and, without further information, the Board is unable to assess whether these studies should be conducted given the need or feasibility of a

[271] For example, at Transcript, Volume 2, page 291, lines 6-10, Mr. Tenney confirmed that ATCO Electric Yukon is one of the members of the Northern consortium, together with three Crown corporations, that fund the research chair in Norther Energy Innovation at Yukon College.
[272] AEY Final Argument, paragraphs 119-122.
[273] JM Final Argument, page 6.

study to support a smart grid project or projects, or whether proposed costs for these studies should be recovered in customer rates.

455. Further, there has been no substantive evidence submitted by parties that provided an indication of any benefits accruing to customers as a result of the proposed study.

456. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecasted expenditures and cost recovery related to its proposals in its compliance filing to this decision.

457. Having made this finding, it is not necessary for the Board to rule on the necessity of a deferral account, the terms of reference or filing any completed Joint Smart Grid Study.

Appendix A – Summary of 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 Board notes AEY's submission that, "Had AEY not revised its methodology… AEY's sales would have varied by more than 1.1% when compared to actuals, as of September 2016." Given these submissions on the 2016 and 2017 numbers, the Board understands that the acknowledged differences using the old or new methodologies would not be significant. Considering the above, AEY has not satisfied the Board that its proposed methodology with respect to using three years for regressing data and normalizing HDD, as well as using the 2013 to 2015 growth rates to derive the forecast UPC, should be adopted. The Board accepts AEY's position that 15 or 20 years may be too long of a timeframe to use in calculating energy sales but it is not convinced that three years is correct for regressing data and normalizing HDD. AEY provided testimony during the course of the hearing that ATCO Gas uses a 10-year timeframe for normalizing over the years to represent more current data. Accordingly, the Board directs AEY, in its compliance filing, to refile its sales and revenue forecast, incorporating its prior methodology using a 10-year timeframe for UPC regression and normalizing HDD. ..... Paragraph 40
2. Regarding the existing financial analysts, the Board notes that the reasoning AEY provided for this change in the supervision of these two positions was to have these analysts more tightly tied to northern operations and northern communities, as opposed to the previous reporting structure. AEY added that those positions work solely for AEY. This rationale is not accepted by the Board because it is unclear how this supervisor position, which is to be based in Yellowknife, is to supervise the work of financial assistants who are based in the Yukon and whose work is carried out entirely in the Yukon, when these positions previously reported to a positon that was tied to AEY operations. Further, AEY has not demonstrated that the other primary function (accounts payable and accounts receivable duties) identified for the Supervisor, Business Support Services, cannot be completed by staff at AEY. Additionally, AEY has not provided any explanation of why the supervisory duties of the Supervisor, Business Support Services could not be carried out by any of the existing accounting positions within AEY. Therefore, the Board concludes that the need for the Supervisor, Business Support Services position has not been justified and directs the positon be removed from AEY's complement. ..... Paragraph 76
3. As a result, for out-of-scope employees, the Board awards for 2016, a labour inflation increment of 0.0 percent because out-of-scope employees did not receive inflationary increments. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 90
4. For these reasons the Board approves a 2017 labour inflation rate for in-scope and out-of-scope employees of 1.9 percent. AEY is directed to reflect this change in its compliance filing to this direction. ..... Paragraph 94

5. The Board notes that AEY provided the May 2016 *Yukon Economic Outlook* in an IR response. In that document, the CPI forecast for Whitehorse for 2016 was 2.0 percent and just under 2.0 percent for 2017. The Board accepts the information provided in the May 2016 *Yukon Economic Outlook* because it is the most up-to-date information on inflation in Yukon on the record. Accordingly, the Board sets the Other Inflation rate for 2016 at 2.0 percent and at 1.9 percent for 2017. AEY is directed to reflect this change in its compliance filing to this decision. ..... Paragraph 105

6. The Board does not accept AEY's submissions that, when considering trends, the total level of O&M costs should be considered or that the review should be limited to those areas with cost variance at the account level. Because of this, the Board believes that a review should be undertaken at the function level for variances in trends, as an inter-relationship between accounts within a function may exist. These inter-relationships may result in misleading trends. Further, at the function level, each function is independent; unless a link is specifically demonstrated, the cost causation in one function does not necessarily lead to cost causation in another function. As a result, the Board directs AEY in its compliance filing and in future GRAs to provide a labour schedule showing total labour costs as well as a breakdown of those labour costs into capital and each of the O&M and A&G functions. This labour schedule is to be provided for each of the test years and the three years prior to the test period. The prior periods will show a labour comparison between forecast and actual. ..... Paragraph 123

7. The Board notes that AEY bases its forecast on historical information, taking into account variance explanations from prior forecasts, and then adds to or reduces the historical amounts based on known upcoming events in the forecast period. However, the Board is concerned about the trends displayed by CW's evidence and finds Attachment 1 to CW-YECL-14 helpful. As noted above, CW evidence is a starting point for further investigation of variance explanations. The Board directs AEY to provide a schedule in future GRAs similar to Attachment 1 to CW-YECL-14, showing labour, fringe and other, comparing actual to approved or forecast levels. The Board also directs that the variance explanations provided in Schedule 5.2 be provided at the labour, fringe and other levels for all future GRAs. ..... Paragraph 124

8. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, "Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period." However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of "Other" for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800 and $7,000 being removed from Account 88900. The revised balance

approved by the Board for 2016 “Other” (Account 88800) is $47,000, and the 2017 balance for “Other” (Account 88800) is $44,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision..... Paragraph128

9. In YUB-YECL-42, AEY was asked to explain the increases in each of the General Accounts (Accounts 88800 and 88900). AEY provided an explanation for Accounts 88800 and 88900 in aggregate, but did not provide an explanation for each account individually. In YUB-YECL-42, AEY did provide an explanation for $32,000, which is the total variance. AEY stated in the Application that, “Ongoing operational and administrative activities are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.” However, the Board finds that $14,000 of the increase from 2015 to 2016 has not been sufficiently explained. In this case, using inflation and a three-year average of costs is duplicative as no specific programs or needs have yet been identified. Therefore, the Board directs that the $14,000 be removed from the 2016 forecast value of “Other” for the aggregate of these accounts (88800 and 88900), with $7,000 being removed from Account 88800, and $7,000 being removed from Account 88900. The revised balance approved by the Board for 2016 “Other”, (Account 88900) is $143,000, and the approved 2017 balance for “Other” (Account 88900) is $146,000. Both balances are subject to changes in the Board-approved inflation rates. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 130

10. The three-year average (2013-2015) for “Other” for Account 72100 is $1,426,000. The Board finds that it is reasonable to use the three-year average for this account. $1,426,000 is the base amount for this account to which inflation is to be applied. Besides inflation, AEY has not provided an explanation for the increase in “Other” costs between 2015 and 2016 and has not justified a different starting base amount for this account. Therefore, starting from the $1,426,000 base amount, the Board has calculated the 2016 forecast value for this account to be $1,455,000. For 2017, the forecast value is $1,483,000. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 134

11. For the purpose of calculating AEY’s depreciation expense for 2016 and 2017, any corrections identified by AEY during the course of the proceeding, or directions made elsewhere in this decision, including those with respect to capital additions, are to be incorporated by AEY. AEY is directed to incorporate these changes in its compliance filing to this decision and its final determination of depreciation expense. ..... Paragraph 163

12. The Board considers that consistent with AEY’s depreciation expense calculations for all other accounts, it is necessary for AEY to incorporate the use of the mid-year convention for Account 493 — Demand Side Management. AEY is directed to revise its depreciation expense calculation for Account 493 — Demand Side Management to reflect a half-year depreciation expense in 2016 for current year capital additions in its compliance filing to this decision.

..... Paragraph 167

13. However, the Board observes that Schedule 7-4, relied on by AEY to support its amortization of accumulated reserve differences amount, disclosed certain negative net salvage percentage information that prompted the clarifications described earlier in this section. The Board considers it would be a simple matter for AEY to have revised Schedule 7-4 to be consistent with the approvals stemming from Board Order 2014-06 and doing so would have avoided unnecessary confusion as to whether the reserve difference amounts complied with Board directions. The Board directs AEY in its future applications, to ensure all supporting schedules filed are consistent with and reflective of Board Orders. ..... Paragraph 172

14. However, in reviewing the AEY response to YUB-YECL-73, the Board notes that actual issue dates for bonds in the years 2011 to 2015 generally occurred before November of the year of issuance. Given that 2016 bonds have been issued before the release of this decision, the Board directs AEY to use the actual cost of debt for 2016 and to reflect this change in its compliance filing to this decision. ..... Paragraph 237

15. As the Board cannot ascertain how AEY determined its credit spread of 1.80 percent, the Board will use the average of credit spreads for the 2011-2016 period. AEY is directed in its compliance filing to this decision to provide an updated table similar to that provided in response to YUB-YECL-73(a) and to update that table to include 2016 actual numbers. In addition, AEY is directed to use the average of the credit spreads for the years 2011-2016, each year given equal weighting, to calculate the credit spread for 2017. The calculated credit spread for 2017 will be added to the updated long Canada bond rate of 2.22 percent and the issue costs of 0.05 percent to determine the cost of debt for 2017.The Board accepts the revised long Canada bond rate proposed by AEY for 2017. AEY is directed to reflect these changes in its compliance filing to this decision. ..... Paragraph 240

16. Considering the above and AEY's submission that it files KPI reports on an annual basis, the Board directs AEY to file on the record of its next GRA, the KPI reports that have been filed with the Board after the record closed in this proceeding. The Board further directs AEY, in its next GRA, to include with the list of improvement projects the reasons for the system deficiency — supported by the KPI filings — that form the basis of the project and the resulting costs. Moreover, AEY is directed to provide a sample report referred to in the quotation above in its next GRA, and to point out and clarify the project expectations — i.e. the expected system performance improvement(s) — that AEY expects will be affirmed by future KPI filings. ..... Paragraph 278

17. Accordingly, the Board directs that all capital costs associated with the end-of-life streetlight conversions be treated as a system cost. ..... Paragraph 292

18. With respect to LED streetlight installations that are not conversions, the Board directs AEY to treat the costs related to new installations or requested conversions as capital costs that attract a full customer contribution in aid of construction. ..... Paragraph 293

19. For the above reasons, the Board is not convinced that the benefits and costs are sufficiently supported to approve the project, and therefore denies the Watson Lake bi-fuel conversion project. AEY is directed to remove the bi-fuel conversion costs from its forecast capital additions in the compliance filing to this decision. ..... Paragraph 354

20. The Board accepts AEY's test period forecast costs because this is an ongoing replacement project. However, because the scope of the project has not been finalized, AEY is directed to provide an updated business case in its next GRA. ..... Paragraph 384

21. If AEY's proposal for alternative 2 (a hybrid system) is explored and is to be implemented, the Board directs AEY to include in its updated business case any revised forecast costs and cost savings. ..... Paragraph 385

22. The Board considers these studies premature and denies cost recovery or deferral treatment for any costs related to a Renewable and Alternative Energy Feasibility study and directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 448

23. Similar to its views respecting the Renewable and Alternative Energy Feasibility Study discussed previously, the Board considers a Joint Smart Grid Study to likewise be premature and denies cost recovery or deferral treatment for any costs related to a Joint Smart Grid study. The Board directs AEY to remove forecast expenditures and cost recovery related to its proposals in its compliance filing to this decision. ..... Paragraph 456

TAB 4

PUBLIC UTILITIES ACT

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

O.I.C. 2019/025

Effective Date:

January 25, 2019

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

DÉCRET 2019/025

Date d'entrée en vigueur :

25 janvier 2019

O.I.C. 2019/025
PUBLIC UTILITIES ACT

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

Pursuant to the *Public Utilities Act*, the Commissioner in Executive Council orders

1 The attached *Direction to the Yukon Utilities Board (Independent Power Production)* is made.

Dated at Whitehorse, Yukon, January 25, 2019.

DÉCRET 2019/025
LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

La commissaire en conseil exécutif, conformément à la *Loi sur les entreprises de service public*, décrète :

1 Est établi l'*Instruction à l'intention de la régie des entreprises de service public (production indépendante d'énergie)* paraissant en annexe.

Fait à Whitehorse, au Yukon, le 25 janvier 2019.

Commissioner of Yukon/Commissaire du Yukon

DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

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DIRECTION TO THE YUKON UTILITIES BOARD (INDEPENDENT POWER PRODUCTION)

1 Definitions

In this Direction

"**ATCO Electric Yukon**" means The Yukon Electrical Company Limited doing business as ATCO Electric Yukon; « *ATCO Electric Yukon* »

"**CPI**" means the All-Items Consumer Price Index for Canada published by Statistics Canada; « *IPC* »

"**electrical grid**" means the interconnected network of equipment and infrastructure, owned by Yukon Energy Corporation and ATCO Electric Yukon, for the generation, transmission and delivery of electricity in Yukon; « *réseau de distribution d'électricité* »

"**electrical grid service area**" means the area of Yukon to which electricity is delivered by means of the electrical grid; « *région desservie par le réseau de distribution d'électricité* »

"**electrical utility**" means Yukon Energy Corporation or ATCO Electric Yukon; « *service public d'électricité* »

"**electricity purchase agreement**" means an agreement between an electrical utility and the owner of an independent power production facility for the purchase, by the utility, of electricity generated by the facility; « *contrat d'achat d'électricité* »

"**generating unit**" means a device used to generate electricity; « *unité de production* »

"**independent power production facility**" means a

INSTRUCTION À L'INTENTION DE LA RÉGIE DES ENTREPRISES DE SERVICE PUBLIC (PRODUCTION INDÉPENDANTE D'ÉNERGIE)

1 Définitions

Les définitions suivantes s'appliquent à la présente instruction :

« **ATCO Electric Yukon** » La Yukon Electrical Company Limited faisant affaires sous le nom d'ATCO Electric Yukon. "*ATCO Electric Yukon*"

« **capacité nominale** » À l'égard d'une installation de production indépendante d'énergie, la puissance maximale de sortie nominale d'électricité de l'installation. "*nameplate capacity*"

« **collectivité hors-réseau** » Beaver Creek, Burwash Landing, Old Crow ou Watson Lake. "*off-grid community*"

« **contrat d'achat d'électricité en réseau** » Un contrat d'achat d'électricité à l'égard d'une installation de production indépendante d'énergie qui est située dans la région desservie par le réseau de distribution d'électricité. "*on-grid electricity purchase agreement*"

« **contrat d'achat d'électricité hors-réseau** » Un contrat d'achat d'électricité à l'égard d'une installation de production indépendante d'énergie qui est située dans une collectivité hors-réseau. "*off-grid electricity purchase agreement*"

« **contrat d'achat d'électricité** » Un contrat entre un service public d'électricité et le propriétaire d'une installation de production indépendante d'énergie pour l'achat par le service public d'électricité produite par cette installation. "*electricity purchase agreement*"

facility in Yukon that

(a) comprises one or more generating units each of which generates electricity exclusively from a renewable energy source,

(b) has a nameplate capacity of at least 30 kW, and

(c) is a prescribed undertaking under the *Independent Power Production and Micro-Generation Regulation*; « *installation indépendante de production d'énergie* »

"**nameplate capacity**", of an independent power production facility, means the maximum rated output of electricity of the facility; « *capacité nominale* »

"**off-grid community**" means Beaver Creek, Burwash Landing, Old Crow or Watson Lake; « *collectivité hors-réseau* »

"**off-grid electricity purchase agreement**" means an electricity purchase agreement in respect of an independent power production facility that is located in an off-grid community; « *contrat d'achat d'électricité hors-réseau* »

"**on-grid electricity purchase agreement**" means an electricity purchase agreement in respect of an independent power production facility that is located in the electrical grid service area; « *contrat d'achat d'électricité en réseau* »

"**renewable energy source**" means

(a) moving water,

(b) wind,

(c) heat from the earth,

(d) sunlight, or

(e) biomass; « *source d'énergie renouvelable* »

"**thermal generation**" means the generation of electricity from diesel or natural gas. « *production thermique* »

« **installation de production indépendante d'énergie** » Une installation au Yukon qui :

a) comprend une ou plusieurs unités de production dont chacune produit de l'électricité exclusivement à partir d'une source d'énergie renouvelable;

b) possède une capacité nominale d'au moins 30 kW;

c) est une entreprise visée par règlement en vertu du *Règlement portant sur la production indépendante d'énergie et la micro-production*. "*independent power production facility*"

« **IPC** » L'indice d'ensemble des prix à la consommation pour le Canada publié par Statistique Canada. "*CPI*"

« **production thermique** » La production d'électricité à partir de diesel ou de gaz naturel. "*thermal generation*"

« **région desservie par le réseau de distribution d'électricité** » La région du Yukon où l'électricité est livrée au moyen du réseau de distribution d'électricité. "*electrical grid service area*"

« **réseau de distribution d'électricité** » Le réseau interconnecté d'équipement et d'infrastructure, appartenant à la Société d'énergie du Yukon et à ATCO Electric Yukon, pour la production, la transmission et la livraison de l'électricité au Yukon. "*electrical grid*"

« **service public d'électricité** » La Société d'énergie du Yukon ou ATCO Electric Yukon. "*electrical utility*"

« **source d'énergie renouvelable** » S'entend des sources suivantes :

a) l'eau en mouvement;

b) le vent;

c) la chaleur de la terre;

d) la lumière du soleil;

e) la biomasse. "*renewable energy source*"

« **unité de production** » Un appareil utilisé pour produire de l'électricité. "*generating unit*"

2 Costs recoverable by electrical utility

(1) In setting rates that an electrical utility is permitted to charge, the board must allow the utility to recover the costs described in subsection (2) if the electricity purchase agreement in respect of which the costs are incurred provides for the matters set out in sections 3 to 6.

(2) For the purposes of subsection (1), the costs are the following:

(a) the cost of purchasing electricity under an electricity purchase agreement;

(b) third party consultant costs, including legal fees, incurred by an electrical utility in relation to the development and implementation of the agreement;

(c) the cost of maintaining or replacing equipment or infrastructure necessary to purchase electricity under the agreement.

3 Price for electricity under electricity purchase agreement

(1) The price paid by an electrical utility for a kWh of electricity under an off-grid electricity purchase agreement

(a) is to be based on the weighted average cost of fuel purchased by the utility for the purpose of producing electricity by means of thermal generation for the five years immediately preceding the date on which the agreement takes effect; and

(b) is to account for any reduction in the maintenance, capital or other costs arising from the displacement of thermal generation as a result of the electricity generated by the facility.

(2) The price paid by an electrical utility for a kWh of electricity under an on-grid electricity purchase agreement is to be based on the utility's average blended fuel price per kWh for thermal generation most recently approved by the board before the date on which the agreement takes effect.

2 Coûts recouvrables par un service public d'électricité

(1) Lorsque la régie fixe les taux qu'un service public d'électricité est autorisé à exiger, elle doit lui permettre de recouvrer les coûts visés au paragraphe (2) si le contrat d'achat d'électricité à l'égard duquel les coûts sont engagés prévoit les éléments énoncés aux articles 3 à 6.

(2) Pour l'application du paragraphe (1), les coûts sont les suivants:

a) le coût d'achat de l'électricité en vertu d'un contrat d'achat d'électricité;

b) les coûts pour un consultant indépendant, y compris les frais juridiques, engagés par un service public d'électricité relativement à l'élaboration et à la mise en œuvre du contrat;

c) les coûts de l'entretien ou du remplacement de l'équipement ou de l'infrastructure nécessaires à l'achat d'électricité en vertu du contrat.

3 Prix de l'électricité en vertu du contrat d'achat d'électricité

(1) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité hors-réseau :

a) repose sur le coût moyen pondéré du combustible acheté par le service public aux fins de production d'électricité par production thermique pendant les cinq années précédant immédiatement la date à laquelle le contrat entre en vigueur;

b) tient compte de toute réduction des coûts d'entretien, d'immobilisations ou autres coûts découlant du déplacement de la production thermique par suite de l'électricité produite par l'installation.

(2) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité en réseau repose sur le prix moyen du combustible mixte par kWh de la production thermique approuvée en dernier lieu par la régie avant la date à laquelle le contrat entre en vigueur.

4 Annual CPI adjustment

(1) The price paid by an electrical utility for a kWh of electricity under an electricity purchase agreement is to be adjusted annually in accordance with subsection (2) or (3).

(2) In the case of an off-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with the percentage increase, if any, in the CPI.

(3) In the case of an on-grid electricity purchase agreement, the price for a kWh of electricity for a particular year is to be determined by increasing the price paid in the year immediately preceding the particular year in accordance with 50% of the percentage increase, if any, in the CPI.

4 Rajustement annuel en fonction de l'IPC

(1) Le prix payé par un service public d'électricité pour un kWh d'électricité en vertu d'un contrat d'achat d'électricité est rajusté annuellement conformément au paragraphe (2) ou (3).

(2) Pour un contrat d'achat d'électricité hors-réseau, le prix d'un kWh d'électricité pour une année donnée est calculé en augmentant le prix payé au cours de l'année précédant immédiatement l'année donnée par l'augmentation en pourcentage, le cas échéant, de l'IPC.

(3) Pour un contrat d'achat d'électricité en réseau, le prix d'un kWh d'électricité pour une année donnée est calculé en augmentant le prix payé au cours de l'année précédant immédiatement l'année donnée par 50 % de l'augmentation en pourcentage, le cas échéant, de l'IPC.

5 Compensation

(1) An electricity purchase agreement is to provide for reasonable compensation to be paid by the electrical utility to the owner of the independent power production facility in the event that the facility is unable to deliver electricity to the utility as a result of damage to, or a failure of, infrastructure or equipment for which the utility is responsible.

(2) An electricity purchase agreement need not provide for reasonable compensation to be paid by the utility to the owner of the facility in the event that the facility is unable to deliver electricity to the utility as a result of a planned outage.

5 Indemnisation

(1) Un contrat d'achat d'électricité prévoit le versement d'une indemnité raisonnable par le service public d'électricité au propriétaire de l'installation de production indépendante d'énergie lorsque l'installation est incapable de lui fournir de l'électricité en raison de dommages ou d'une défaillance des infrastructures ou de l'équipement dont le service public est responsable.

(2) Un contrat d'achat d'électricité n'est pas tenu de prévoir une indemnisation raisonnable que le service public doit verser au propriétaire de l'installation dans l'éventualité où l'installation est incapable de lui fournir de l'électricité en raison d'un arrêt planifié.

6 Term of electricity purchase agreement

The term of an electricity purchase agreement is to be at least 20 years.

6 Durée du contrat d'achat d'électricité

La durée d'un contrat d'achat d'électricité est d'au moins 20 ans.

TAB 5

Yukon's Independent Power Production Policy

Updated October 2018

BACKGROUND

The Government of Yukon (YG) released the Energy Strategy for Yukon in January 2009. The strategy sets out YG's energy priorities, strategies and actions. The Independent Power Production (IPP) Policy is part of the strategy's priority action to "update and develop a policy framework for electricity that emphasizes efficiency, conservation and renewable energy." The policy provides a mechanism for the purchase of electricity from IPPs.

A Discussion Paper on net metering and IPP was released for public consultation between November 2009 and February 2010. Through that consultation, the public clearly indicated that there should be separate policies for net metering and IPP. Valuable input was received about proposed policy objectives, eligible energy sources, size of electricity projects, connections to the Yukon electrical grid, financial arrangements, policy framework and roles and responsibilities.

The IPP Policy was adopted in October 2015. The IPP Policy is about providing opportunities for non-utility entities to generate new power that can assist the utilities in meeting the demand for affordable, reliable, flexible and clean electrical energy.

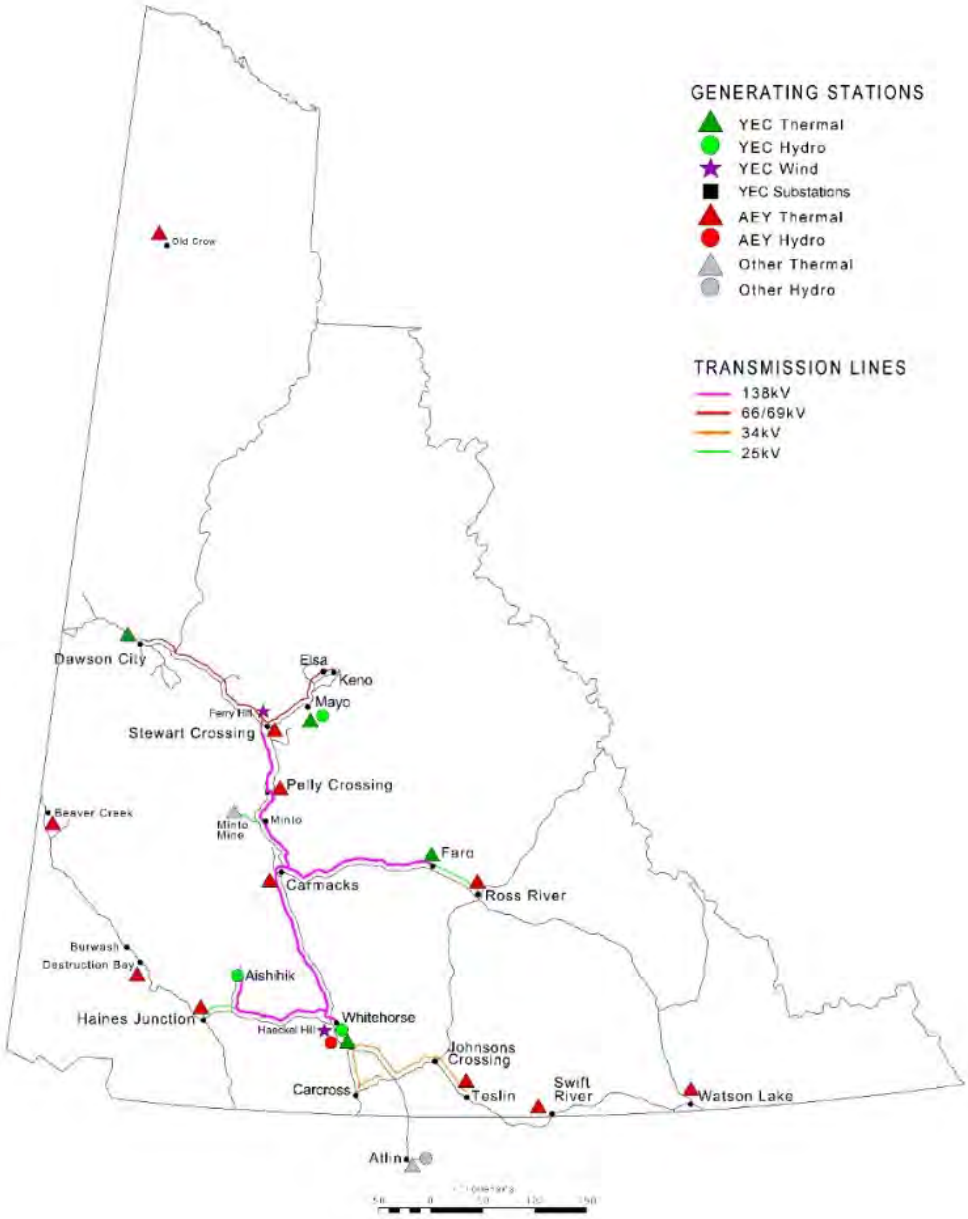
The IPP Policy will look different in Yukon than it does in other jurisdictions. Yukon's electrical grids are not connected to the North American grid and are smaller than other jurisdictions' grids. The inability to export excess electricity makes it risky for the utilities and Yukon ratepayers to generate electricity in anticipation of increased demand, as this future demand may not materialize in Yukon's commodity-based economy. At the same time, Yukon is unable to import electricity when required, making growth in local generation capacity crucial to future economic and population growth.

As of 2018, the electrical system in Yukon (shown in map below) is comprised of:

- 1 large hydro-based grid called the Yukon Integrated System;
- 1 medium-sized diesel-based grid serving Watson Lake; and
- Three smaller isolated communities with diesel generation (Old Crow, Beaver Creek and Destruction Bay/Burwash Landing).

Yukon's electricity demand in 2016 (the last year for which we have data) was 450.9 gigawatt hours, 94.1 per cent of which was generated through renewable energy sources. Demand continues to grow, however, and may soon be in excess of Yukon's renewable energy capacity. To avoid the use of thermal-generated electricity, and if the residential, commercial and industrial loads continue to grow as forecast, this (hydro-based) grid will require additional renewable sources of energy.

Electrical Generation and Transmission System for Yukon



SCOPE

Application

This policy applies to IPPs who want to generate electricity from eligible sources and sell it to a publicly-owned utility, Yukon Energy Corporation or ATCO Electric Yukon.

This policy does not apply to producers covered under YG's Micro-generation Policy.

Policy Goal and Objectives

The goal of this policy is to support the participation of IPPs, including Yukon First Nations and communities, in the development and expansion of environmentally sound and affordable electrical supply options now and into the future, while respecting the integrity of the existing electrical system.

The objectives of the IPP Policy are to:

1. Increase electrical supply to meet future energy needs;
2. Strengthen energy security and affordability of Yukon's electrical system;
3. Develop local electricity resources, which are renewable and/or cleaner than diesel;
4. Encourage new, local economic opportunities;
5. Provide Yukon First Nations with opportunities to participate in the Yukon economy, obtain economic benefits, and develop economic self-reliance; and
6. Facilitate collaboration between public utilities and IPPs, in the development of new clean energy supply projects, which best serve the long-term interests of Yukon consumers.

IPP Target

In order to meet these objectives, this policy will establish the following aspirational targets for IPP contribution to Yukon's electrical grids.

1. 10 per cent of new electrical demand to be met by IPP; and
2. At least 50 per cent of IPP projects to have a Yukon First Nation ownership component.

POLICY PARAMETERS

This policy establishes three separate approaches for development of IPP projects. For small, simple projects, a Standing Offer Program will be established. A Call for Power process will be established to allow the territory's energy planners to access IPPs to meet expected large-scale electrical demands. And for large-scale projects that are primarily being developed by communities, an Unsolicited Proposal process would allow an IPP to propose a generation project at any time. Details are as follows.

Eligible Energy Sources

Eligible energy sources for IPP projects are limited to local renewable sources as discussed in the Energy Strategy for Yukon, which include:

- wind
- hydro
- geothermal
- biomass
- solar

1. Standing Offer Program

The Standing Offer Program encourages the development of new, small and renewable projects. The intention of the program is to streamline the process for selling electricity to Yukon Energy Corporation on the Yukon Integrated System and to ATCO Electric Yukon in Watson Lake, and to simplify the contracting process between IPP developers and the utilities. Details of the program will be completed by the utilities and YG on or before January 1, 2019.

Remote Communities and the Standing Offer Program

Due to the isolated nature of the three smaller communities with diesel generation (Old Crow, Beaver Creek and Destruction Bay/Burwash Landing) and the relatively small size of the generating facilities in these communities, a cautious approach is required to ensure the safety and security of the electrical grid for all residents. For this reason, these sites are not eligible for the Standing Offer Program. Potential IPPs in these communities are, however, eligible for the Unsolicited Proposal processes described below. As well, smaller systems (up to 50 kilowatts) are eligible for the Micro-generation Production Incentive Program and proponents would be offered an incentive through that program.

In addition, YG is committed through this policy to work with these communities and the local electrical utility (ATCO Electric Yukon) to provide resources that will facilitate the development of community-owned IPP projects, such that these communities can develop economic and energy self-reliance, while reducing the greenhouse gas emissions from diesel generation.

Connecting the Standing Offer Program Projects to the Electrical Grids

The utilities and YG will develop all required interconnection materials (i.e., interconnection standards, interconnection agreement templates and Standing Offer Program pricing information) on or before January 1, 2019 and file the interconnection standards and agreement templates with the Yukon Utilities Board for information at an appropriate time.

New technologies will be considered when this policy is reviewed.[1] Electricity-generating technologies and energy sources must be proven to be reliable before they will be accepted for interconnection to Yukon's electrical grid.

Standing Offer Program Project Size and System-Wide Limits

Standing Offer Program projects must be between 30 kilowatts and 2,000 kilowatts in nameplate capacity in order to be considered.

Any renewable energy electrical generation project under 50 kilowatts can be included in the Micro-generation Production Incentive Program if the project offsets a building's energy consumption and electricity is exported to the grid; however, proponents are required to choose between the IPP or Micro-generation policies.

System-wide limits under the Standing Offer Program are set by the utilities, Yukon Development Corporation and YG's Energy Branch to meet the policy objectives (listed above), while also observing the technical limitations of Yukon's electrical system and minimizing financial risks to Yukon's electrical customers. On the Yukon Integrated System, system-wide limits will be phased in over time to reflect expected increases in electrical loads over time. The following table lists the targeted initial system wide limits for the Standing Offer Program for both the Yukon Integrated System and Watson Lake grid. These limits will be evaluated and revised every two years by the two Yukon **ut**ilities, Yukon Development Corporation and YG's Energy Branch.

[1] This policy will be reviewed every two years, beginning two years from its implementation date.

Grid	System-Wide Generation Limits
Yukon Integrated System	20,000 megawatt hours/year
Watson Lake	2,100 megawatt hours/year

Standing Offer Program Interconnection Agreement and Agreement to Purchase Power Principles

The following principles will be used in the development of interconnection agreements and internal policy for the Standing Offer Program:

1. Utilities will work with the YG's Energy Branch to establish and publish a rate under the Standing Offer Program for delivered energy based on current avoided costs of thermal generation. Accordingly, rates can be higher in the winter than in the summer. These rates will be indexed to reflect appropriate annual inflation in costs; specifics will be outlined in an Order-in-Council.
2. The utilities will work with YG to ensure that the proposed IPP rates will be based on the avoided cost of thermal generation.
3. IPP rates are to provide potential proponents with pricing and market certainty for their generated power.
4. The contract term will be of a duration that enables the prospective independent power producer to access independent financial support.
5. The contract term will be of a duration that fits with the proposed technology's (anticipated) life expectancy, reliability and associated utility risks.
6. IPPs will be responsible for interconnection costs and necessary interconnection upgrades, as well as maintenance of their infrastructure.
7. Each utility will retain the right to cancel or suspend the Interconnection Agreement and the Agreement to Purchase Power, if the IPP no longer meets the requirements as outlined in the Agreement to Purchase Power and the Interconnection Agreement.

2. Call for Power

A Call for Power applies to projects larger than the above system-wide limits on Yukon's Integrated System. The Call for Power will require government approval. The Call for Power process will be used by Yukon Energy Corporation to incorporate large-scale IPP projects into Yukon's electrical system. The Call for Power process is proposed to meet future electrical needs, and to fulfil the objectives and targets set out in the above sections.

The Agreement to Purchase Power will be negotiated by Yukon Energy Corporation and the IPP, and will require final approval by the Yukon Utilities Board.

Connecting Call for Power Projects to the Electrical Grid

When Yukon Energy Corporation and/or Yukon Development Corporation determines that there is a need for new electrical generation above and beyond the system-wide limits set in the table above, Yukon Energy Corporation may release a Call for Power for IPP electrical generation, consistent with the objectives of this policy. Yukon Energy Corporation will review and assess proposals, based on criteria to be developed by the corporation in consultation with YG's Energy Branch.

Draft agreements to purchase power from potential producers who have submitted successful proposals will be brought forward to the Yukon Utilities Board by Yukon Energy Corporation for approval.

Call for Power Project Size and Technology Limitations

No limitations on either project size or technology will be set on Call for Power type projects. These parameters will be established by Yukon Energy Corporation in consultation with YG and Yukon Development Corporation at the time in which the process is developed, based on the current needs of the territorial electrical system and this IPP Policy.

Call for Power Interconnection Agreement and Agreement to Purchase Power Principles

The Agreement to Purchase Power under a Call for Power will be developed for each individual call. The following principles will be used by Yukon Energy Corporation in the development of power purchase agreements under a Call for Power:

1. IPP rates are to provide potential proponents with pricing and market certainty for their generated power.
2. The contract term will be of a duration that enables the prospective IPP to access independent financial support.
3. The contract term will be of a duration that fits the proposed technology's anticipated life expectancy, reliability and associated utility risks.
4. In evaluating projects, preference will be given to those projects which include First Nation ownership (see definitions below).
5. The IPP will be responsible for interconnection costs and necessary interconnection upgrades, as well as maintenance of its electrical infrastructure.
6. Each utility will retain the right to cancel or suspend the Interconnection Agreement and the Agreement to Purchase Power if the IPP_ no longer meets the requirements as outlined in the Agreement to Purchase Power and the Interconnection Agreement.

3. Unsolicited Proposals

Unsolicited proposals can be submitted to the utilities or YG's Energy Branch at any time for projects larger than the Standing Offer Program system-wide limits (on the Yukon Integrated System or in Watson Lake), or any systems installed in the three smaller isolated communities (Old Crow, Beaver Creek and Destruction Bay/Burwash Landing). Eligibility of proposals will be assessed based on current energy needs in the territory, as well as the principles established through this policy. The utilities will negotiate power purchase agreements with IPP proponents to enable project development(s), should they be in the best interest of the territory. YG's Energy Branch will offer support to IPPs in navigating the power purchase agreement development process.



ROLES AND RESPONSIBILITIES

Joint Responsibilities of the Government of Yukon and the Utilities

1. Implement, maintain and communicate this policy.
2. Evaluate this policy every two years, beginning two years from its effective date.
3. Develop the Standing Offer Program (including the rates to be paid), technical interconnection standards, and interconnection agreement templates for program projects.

Government of Yukon

1. Ensure this policy is consistent with the Energy Strategy for Yukon, the Climate Change Action Plan, the Water Strategy and other government priorities and trade agreements.
2. Meet obligations under First Nation Final Agreements and ensure that this policy is consistent with those obligations.
3. Facilitate First Nation economic development through risk sharing on projects with First Nation IPPs.
4. Encourage IPP proponents to partner with Yukon First Nations and/or Yukon First Nation development corporations and Yukon businesses.

Utilities (Yukon Energy Corporation/ATCO Electric Yukon)

1. Determine whether Standing Offer Program applicants meet interconnection standards and are therefore eligible to participate in the program.
2. Develop and manage the Request for Proposal process for Call for Power projects. Develop interconnection standards and Agreements to Purchase Power for Call for Power projects.
3. Meet utilities' commitments within interconnection agreements.
4. Provide the public with annual, hourly energy demand data that could be used in assessing the viability of and need for proposed IPP projects in the territory.



Yukon Utilities Board

1. Where required, review Call for Power and Unsolicited Proposal projects per the *Public Utilities Act*, and if approved, include in electrical rates.

Yukon Development Corporation

1. Assist YG and the utilities in the implementation of this policy, including setting system-wide limits for the Standing Offer Program and parameters for the Call for Power.

Independent Power Producer

1. Enter into an interconnection agreement and an Agreement to Purchase Power with the appropriate utility prior to connection to the electrical grid.
2. Be responsible for obtaining all permits and paying associated costs.
3. Be responsible for initiating all environmental and/or regulatory obligations related to its project.
4. Make available the electrical generation project for inspection by the utilities or the applicable government agency, as per the interconnection agreement and Agreement to Purchase Power.
5. Develop a business case and conduct project analysis, including review and screening, permitting, licensing and meeting land tenure requirements.
6. Be responsible for costs associated with project feasibility assessments.
7. Be responsible for securing technical, legal and financial advice.
8. Meet requirements of the interconnection agreement.
9. Be responsible for addressing requirements of the First Nation land claim agreements, including appropriate consultation.

DEFINITIONS

Agreement to Purchase Power — An agreement between the prospective IPP and a utility for the purchase of power from the IPP by the utility.

ATCO Electric Yukon — A private investor-owned utility, and member of the ATCO Group of Companies.

Avoided Costs — Avoided costs represent expenditures that are reduced when thermal generation is replaced through renewable energy, energy storage and energy system management systems over the full term of the IPP project.

Biomass (energy) — Energy harnessed through combustion of organic matter, including wood and agricultural waste.

Call for Power — A process to permit IPPs to generate and contribute power to the grid, meeting expected larger-scale electrical demand.

First Nation Ownership — Part or complete ownership of an IPP project by a Yukon First Nation government, a Yukon First Nation development corporation, or other agencies of a Yukon First Nation that are at least 50 per cent owned and controlled by a Yukon First Nation(s).

Geothermal (energy) — Energy derived from geothermal resources, which are steam, water or vapour (greater than 80° C) and all substances dissolved in the steam, water or vapour.

Hydro (energy) — Potential or kinetic energy of water.

Independent Power Producer (IPP) — An agency or individual other than a public utility (as defined by the *Public Utilities Act*) who generates electricity to sell (to the utilities). An IPP does not own transmission facilities and is dependent on the utilities to purchase and distribute the power it produces.

Kilowatt — A unit of electric power. One kilowatt is equal to 1,000 watts.

Kilowatt hour — A unit of energy equivalent to one kilowatt of power expended for one hour of time.

Nameplate capacity — The power output of an electrical generation plant under ideal conditions, usually expressed in kilowatts or megawatts.

Public Utility — As defined by the *Public Utilities Act and Regulations* (i.e., Yukon Energy Corporation and/or ATCO Electric Yukon).

Solar energy — Radiant light or heat from the sun. This is used to generate electricity by converting the light or heat using photovoltaics and solar thermal technologies.

Standing Offer Program — A program that enables Yukon public utilities (i.e., Yukon Energy Corporation, ATCO Electric Yukon) to purchase electricity from IPPs.

Thermal generation — Refers to the process of generating electricity from heat. There are five thermal energy fuels: coal, natural gas, diesel, wood waste and geo-thermal. In Yukon, this refers to diesel and natural gas exclusively.

Utility — See Public Utility (i.e., Yukon Energy Corporation and/or ATCO Electric Yukon)

Wind energy — Kinetic energy of wind. Electricity is produced from a system of airfoils or blades that spin a drive shaft to capture the energy.

Yukon Energy Corporation — A publicly-owned electrical utility that is the main generator and transmitter of electrical energy in Yukon.

(YG) Energy Branch — A branch of YG's Department of Energy, Mines and Resources. The Energy Branch's mandate is to facilitate the coordinated, effective and collaborative delivery of energy policy, projects and programs to promote a secure Yukon energy sector that is environmentally, economically and socially responsible.

Yukon Integrated System — The integrated Whitehorse-Aishihik-Faro and Mayo-Dawson electrical grids which are owned by Yukon Energy Corporation.

Yukon Utilities Board — The board gets its mandate from the *Public Utilities Act*. It fixes rates, standards, classifications, regulations, practices, measurements or services to be observed, provided or followed by a public utility.

TAB 6

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Utilities Commission

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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

Purpose of the Proceeding

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.

[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

[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.

[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.

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 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

[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.

utilities, US utilities, and North American utilities proxy groups, and then average the results of each of these proxy groups.[56]

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

[56] Ibid., p. 42.
[57] RCIA Final Argument, p. 17.
[58] FortisBC Reply Argument, pp. 55–56.
[59] FortisBC Reply Argument, pp. 57–58.
[60] Ibid., p. 57.

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]

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,

[61] Ibid., p. 58.
[62] FortisBC Reply Argument, p. 58.
[63] Ibid., p. 59.

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 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;

[64] Exhibit A2-3, Lesser Report, pp. 14–15.

- 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
- 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%**

[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.

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, 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%**

[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.

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 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

[73] Exhibit B1-8-1-2, pp. 2, 4.

[74] Information in the table has been compiled from Exhibit B1-8-1-2, Figures 3 and 4, p. 6.

[75] See footnote 67.

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 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%**

[76] Exhibit B1-8-1-2, pp. 6–7.

[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.

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 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

ICG

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]

BCOAPO

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.

The CEC

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

[81] Transcript Volume 4, p. 574, Lines 11–12.
[82] FortisBC Final Argument, p. 121.
[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.

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]

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

[87] The CEC Final Argument, p. 38, 43.
[88] Ibid., p. 44.
[89] FortisBC Reply Argument, pp. 50–51.
[90] FortisBC Final Argument, p. 146.

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.

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

[91] Ibid., p. 122.
[92] The CEC Final Argument, p. 38, 43.
[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.

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 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

[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.
[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.

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 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]

FEI

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]

[105] 2013 Decision, p. 48.
[106] Exhibit B1-13, RCIA IR 2.2.1 and 4.1.2.
[107] 2013 Decision, pp. 48–50.
[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.

> 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]

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

[116] Ibid., p. 2.
[117] Exhibit B1-8-1, Appendix C, p. 80.
[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.

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]
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]

FBC

[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.
[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.

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.

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

[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.
[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.

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]

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]

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[141] Ibid., p. 2.
[142] FortisBC Final Argument, p. 116.
[143] The CEC Final Argument, pp. 49–50.
[144] BCOAPO Final Argument, p. 70.
[145] BCOAPO Final Argument, p. 68.
[146] ICG Final Argument, pp. 16–17.

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 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.

[147] FortisBC Reply Argument, p. 39.

[148] 2013 Decision, p. 48.

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 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

[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.
[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.

Business Risk Category	Risk Factor	Change in Risk Since 2016
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

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

[155] Exhibit B1-9, BCUC IR 4.1.

[156] Exhibit B1-8, p. 3.

[157] Exhibit B1-9, BCUC IR 4.1.

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 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]

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[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.
[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.

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 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

[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.
[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.

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]
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

[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.
[182] FortisBC Reply Argument, p. 18.
[183] Exhibit B1-8-1, Appendix A, p. 4.
[184] Ibid.

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]

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

[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.
[191] RCIA Final Argument, p. 31.
[192] Ibid., pp. 29–30.
[193] FortisBC Reply Argument, p. 20.

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]

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

[194] Exhibit B1-8-1, Appendix A, pp. 4–5, 44.
[195] BCOAPO Final Argument, p. 17.
[196] BCOAPO Final Argument, p. 18.
[197] Ibid., p. 17.
[198] FortisBC Reply Argument, p. 11.

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 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

[199] Ibid., p. 5.
[200] The CEC Final Argument, p. 18.
[201] Ibid., p. 17.
[202] FortisBC Reply Argument, pp. 20–21.
[203] Ibid.
[204] FortisBC Reply Argument, p. 21.
[205] Ibid., p. 6.
[206] Exhibit B1-8-1 Appendix A, pp. 53–78.

- 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]

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]

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[207] Ibid., pp. 5, 70.
[208] BCOAPO Final Argument, pp. 18–19.
[209] Ibid., p. 19.
[210] FortisBC Final Argument, p. 21.
[211] The CEC Final Argument, pp. 19–20.
[212] Ibid., p. 20.

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]

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;

[213] FortisBC Reply Argument, p. 22.
[214] MoveUP Final Argument, p. 3.
[215] FortisBC Reply Argument, pp. 3–4.
[216] Exhibit B1-8-1, Appendix A, pp. 5, 78–88.

- 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]

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

[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.
[223] FortisBC Reply Argument, pp. 22–23.
[224] The CEC Final Argument, p. 22.
[225] Ibid., pp. 21–22.

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 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

[226] FortisBC Reply Argument, pp. 23–24.
[227] RCIA Final Argument, p. 26.
[228] Ibid., p. 27.
[229] FortisBC Reply Agrument, pp. 24–25.
[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.

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]

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]

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[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.
[239] BCOAPO Final Argument, p. 23.
[240] BCOAPO Final Argument, p. 23.
[241] Ibid.
[242] FortisBC Reply Argument, p. 25.

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]

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

[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.
[249] Exhibit B1-8-1, Appendix A, p. 115.
[250] Exhibit B1-8-1, Appendix A, p. 115.

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 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]

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[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.
[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.

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 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

[262] BCOAPO Final Argument, p. 15.

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 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 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).

[263] The CEC Final Argument, p. 9.
[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

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.

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

[268] Exhibit B1-8, p. 2

[269] Exhibit B1-8-1, Appendix B, p. 1.

[270] Ibid.

[271] Exhibit B1-8-1, Appendix B, p. 2–3.

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.

Business Profile

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. 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

[272] Exhibit B1-8-1, Appendix B, p. 3, Exhibit B1-8, p. 19.

[273] Exhibit B1-9, BCUC IR 33.9.

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]

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]

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[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.
[280] BCOAPO Final Argument, p. 14, 29.
[281] The CEC Final Argument, p. 31.
[282] FortisBC Reply Argument, p. 32.

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]

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

[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.
[290] ICG Final Argument, p. 4.

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]

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

[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.
[296] FortisBC Reply Argument, pp. 33–34.

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.

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.

[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.
[304] Exhibit B1-8-1, Appendix B, p. 25.

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 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

[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.
[312] The CEC Final Argument, p. 33.
[313] FortisBC Reply Argument, p. 34.

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.
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]

[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.
[317] Exhibit B1-8, p. 20.

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]

Regulatory

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 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]

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[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.
[322] Exhibit B1-8, p. 20.

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 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

[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.

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 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].

[329] The CEC Final Argument, p. 30.
[330] RCIA Final Argument, p. 31.
[331] ICG Final Argument, p. 16.
[332] BCOAPO Final Argument, p. 36.
[333] Ibid.

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 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

[334] Exhibit A2-3, p. 22.
[335] Exhibit B1-8-1, Appendix C, p. 45.
[336] Exhibit A2-3, p. 22.
[337] Exhibit A2-3, p. 23.
[338] Ibid.

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 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]

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[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.
[343] Exhibit B1-9, BCUC IR 44.3.
[344] FortisBC Final Argument, p. 136.

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:

$$K_e = rf + \beta(rm - rf) \qquad (1)$$

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

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;

[345] BCOAPO Final Argument, p. 37.

[346] 2013 Decision, 2016 Decision.

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 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]

[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.
[354] Exhibit A2-3, p. 46.

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%

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

[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).

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]

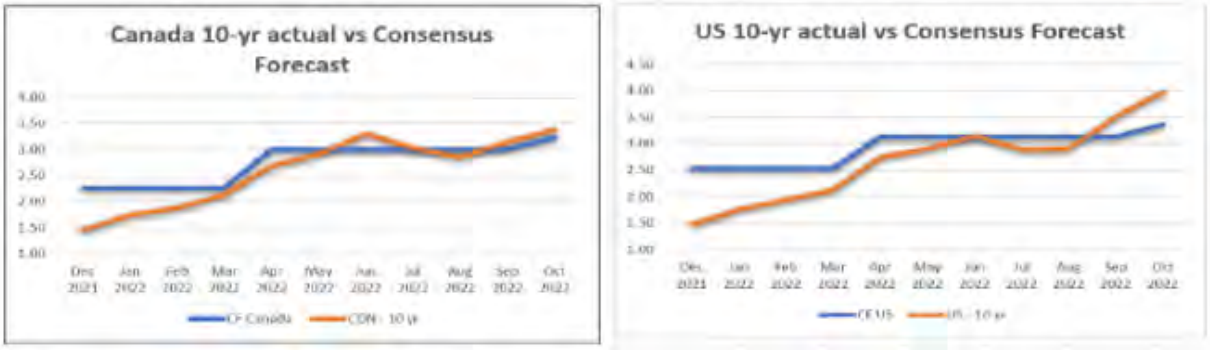
Regarding Dr. Lesser's view that based on the Efficient Market Hypothesis, "using a forecast of future yields on such bonds thus amounts to "double-counting" future expectations."[362] FortisBC remarks that Dr. Lesser concedes that "double- counting" is a misnomer, as Mr. Coyne is using the forecast 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]



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.

[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.

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

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

[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.

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 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.

[372] FortisBC Reply Argument, pp. 63–64.
[373] FortisBC Reply Argument, pp. 62–63.
[374] Ibid., p. 62.

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

BCOAPO

[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.

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 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]

The CEC

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]

RCIA

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]

FortisBC Reply Argument

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

[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.

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]

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

[399] FortisBC Reply Argument, p. 46.

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]

[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.

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 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]

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[404] Exhibit B1-8-1, Appendix C, p. 61.
[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.

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]

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%

[413] Exhibit B1-8-1, Appendix C, p. 60.

[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.

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. 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]

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[418] FortisBC Final Argument, pp. 163–164.
[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.

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. 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

[424] BCOAPO Final Argument, p. 50.
[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.

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]

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

[430] Ibid., pp. 41–42.
[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%.

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]

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]

[437] (7.32%-6.43%) x 0.89 (Beta).
[438] RCIA Final Argument, p. 19.
[439] FortisBC Reply Argument, pp. 69–70.
[440] FortisBC Reply Argument, p. 70.
[441] Ibid., p. 44.
[442] Ibid., pp. 45, 70.

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]

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.

[443] Ibid., pp. 42-43

[444] FortisBC Reply Argument, pp. 64–67.

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 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

[445] Exhibit B1-9, BCUC IR 39.8.2.
[446] (7.74+8.21)/2.
[447] (5.74+7.46)/2.
[448] Exhibit A2-3, p. 47.

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.

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]

[449] Exhibit B1-8-1, Appendix C, p. 60.
[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.

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]

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

BCOAPO

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]

The CEC

[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.
[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.

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]

FortisBC Reply Argument

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 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%

[467] The CEC Final Argument, pp. 55–56.

[468] FortisBC Reply Argument, p. 47.

[469] Exhibit B1-50, Table 3, Scenario A.2, p. 4.

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:

- 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

ICG

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]

[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.

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 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

[476] Exhibit B1-50, Scenario B.6, Figure 12, p. 10.

[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.

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 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]

[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.

RCIA

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]

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 %**

FortisBC Reply Argument

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

[485] RCIA Final Argument, pp. 10–11.
[486] Ibid., p. 20.
[487] FortisBC Reply Argument, pp. 55–56.
[488] Including a 50-bps adder for flotation cost and financial flexibility.

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;
- 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.

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[489] Including a 50-bps adder for flotation cost and financial flexibility.

[490] FortisBC Reply Argument, p. 50.

[491] Ibid., p. 53.

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.

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).

[492] Calculated by the BCUC using the Average function in Excel = Average (11.69%,10.03%,9.05%,9.39%,9.35%) = 9.90%.

[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.

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

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.

[496] Exhibit B1-8-1, Appendix C, p. 48.
[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.

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 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

[503] FEI Final Argument, p. 174.
[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.

> 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:

> 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]

[509] Exhibit B1-8-1-2, p. 4.
[510] Ibid., pp. 4–5.
[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.

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]

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

Analysts' forecasts in First Stage

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.

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[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.

[518] Exhibit A2-20, BCUC IR 5.4.

[519] Exhibit B1-8-1, Appendix C, pp. 49–50.

[520] Exhibit A2-3, p. 27.

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 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,

[521] Ibid., p. 31.
[522] Exhibit B1-8-1, Appendix C, p. 49.
[523] Transcript Volume 3, p. 314.
[524] Ibid., pp. 314–315.
[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.

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 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.

[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.
[536] Transcript Volume 3, p. 264.
[537] Ibid., p. 262.

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.

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

[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.
[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.

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.

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

[546] FortisBC Final Argument, pp. 136–137.
[547] Ibid., p. 137.
[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.

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]



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 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

[550] FortisBC Final Argument, pp. 151–153.
[551] Exhibit B1-43; FortisBC Final Argument, p. 153.
[552] FortisBC Final Argument, p. 153.
[553] Ibid., pp. 154.
[554] Ibid., pp. 154–155.

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 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]

[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.
[558] FortisBC Final Argument , pp. 148–149.
[559] ICG Final Argument, p. 9.
[560] Ibid., para. 33, p. 15.

> 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 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]

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[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.
[564] BCOAPO Final Argument, pp. 39–40.
[565] Ibid., p. 40.
[566] Ibid., p.41.

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]

The CEC

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]
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]

[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.
[571] The CEC Final Argument, para. 296, p. 42.
[572] Ibid., paras. 299–300, p. 43.

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 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

[573] Ibid.

[574] Table created from Table 26 figures with 50 bps subtracted.

[575] FortisBC Reply Argument, p. 59.

[576] FortisBC Reply Argument, pp. 59–60.

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".

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

[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.

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.

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 Jersey 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.

[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%.

[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%.

Table 30: 30-Day Multi-Stage DCF - North American Electric Utilities[586]

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Growth Rate, Years 1-5	[4] Year 6	[5] Year 7	[6] Year 8	[7] Year 9	[8] Year 10	[9] GDP Growth (perpetuity)	[10] 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 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

[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.
[588] Exhibit A2-3, p. 60.

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.

$$ERP = a + (b \times Y) \qquad (7)$$

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: $ERP = 0.0843 - 0.5432 \times Y$

Figure **3**: Risk Premium Results - U.S. Gas[593]

[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".
[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.

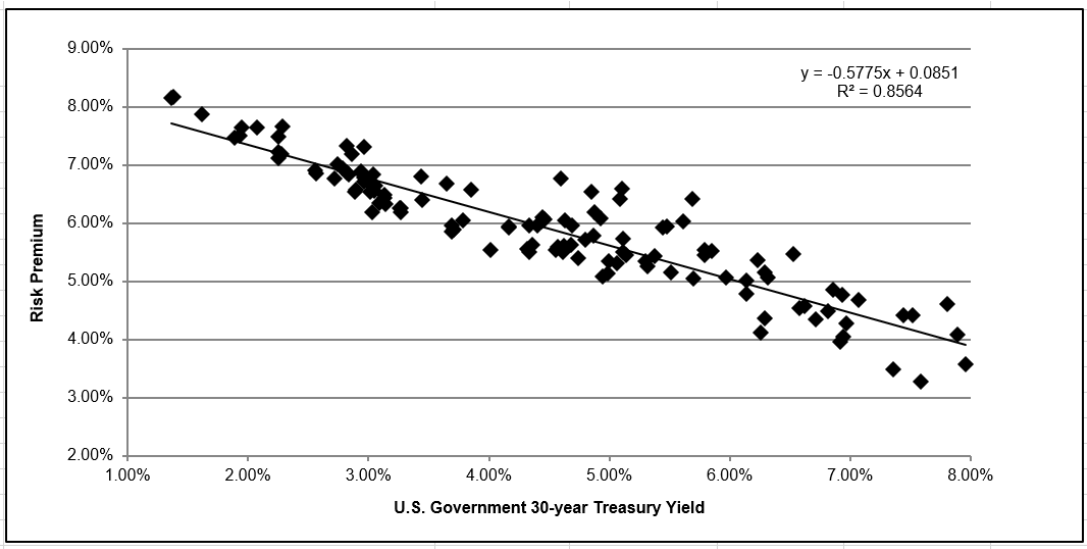
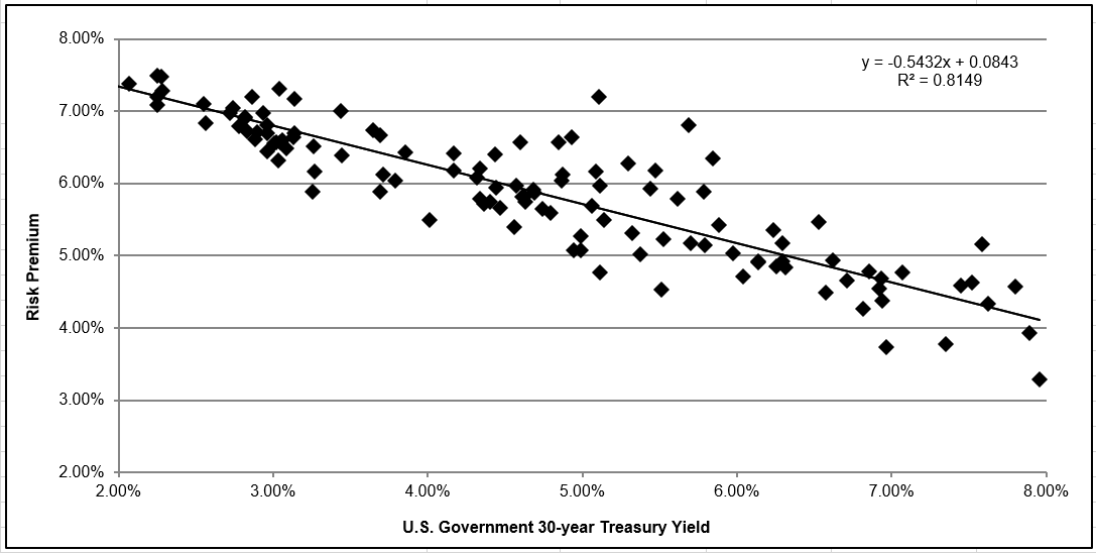


Figure **4**: Risk Premium Results - U.S. Electric[594]



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 would a regulator say about the allowed return, with no other information available to them but

[594] Exhibit B1-8-1, Appendix C, p. 65.

[595] Transcript Volume 4, p. 654, Lines 18–26 to p. 655, Lines 1–16.

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 its implementation. For instance, the regression specification (with only one explanatory variable) assumes that

[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.

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

[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]

[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.

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 (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.

[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

[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.

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 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

[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.

flexibility in order to manage a capitalization that is "conservative and takes into account market disruptions so 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.

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[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

[690] Exhibit A2-20, BCUC IR 6.6.
[691] Exhibit B1-51, BCUC IR 1.1.

reasonable expenditure. Those expenditures, if and as incurred, can be recovered from the ratepayers of FEI, or 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]

[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.

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.

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]

[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.

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%

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]

[701] Ibid., Figure 65, p. 151.
[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.

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%

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

[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.

[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.

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]

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

[710] FortisBC Reply Argument, pp. 55–56.
[711] Ibid., p. 55.
[712] FortisBC Reply Argument, p. 44.
[713] Ibid., p. 45.
[714] Ibid., p. 46.
[715] FortisBC Reply Argument, p. 46.

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 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

[716] Ibid., p. 47.

[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.

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 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

[721] 9.43% + 0.47% = 9.90%.

[722] FortisBC Reply Argument, p. 51.

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.**

[723] FortisBC Reply Argument, p. 43.

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 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.

[724] ICG Final Argument, pp. 3–4.
[725] Ibid., p. 10.
[726] Ibid., p. 16.

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]

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]

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[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.
[730] Order G-106-22, Reasons for Decision, p. 4.
[731] FortisBC Final Argument, p. 199.

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]

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]

[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.
[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.

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 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

[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.
[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.

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 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

[754] Corix Submission dated May 31, 2023, p. 4.
[755] FAES Response dated June 14, 2023, pp. 1–2.
[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.

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.
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.
    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.

[758] Order G-106-22, Appendix C.
[759] Order G-183-21.

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]
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

[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.
[766] 2013 Decision, p. 88.
[767] Ibid., p. 90.
[768] Ibid., p. 91.
[769] Ibid.
[770] 2016 Decision, p. 89.

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 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

[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.
[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.

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 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

[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.
[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.

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]

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]

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[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.
[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.

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.

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.

[811] FortisBC Reply Argument, p. 80.
[812] Ibid.
[813] Ibid.
[814] Ibid., pp. 80–81.

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]
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

[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.
[823] BCOAPO Final Argument, p. 72.
[824] FortisBC Reply Argument, p. 82.

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.

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.

[825] Ibid., p. 83.
[826] Ibid.
[827] RCIA Final Argument, p. 34.
[828] FortisBC Reply Argument, p. 82.
[829] Ibid., p. 83.

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
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

[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.
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:

_____

D. M. Morton

Panel Chair / Commissioner

Original signed by:

_____

A. K. Fung, KC
Commissioner

Original signed by:

_____

K. A. Keilty
Commissioner

Original signed by:

_____

T. A. Loski
Commissioner

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

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

Exhibit No.	Description
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

Exhibit No.	Description
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

Exhibit No.	Description
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
C5-6	Letter dated October 15, 2021 – ICG submitting Information Request No. 1 on Exhibit A2-3
C5-7	Letter dated March 7, 2022 – ICG submitting Information Request No. 1 on FortisBC Evidence
C5-8	Letter dated May 16, 2022 – ICG submitting Information Request No. 2 to Dr. Lesser regarding Mr. Coyne's evidence
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

TAB 7

IN THE MATTER OF the *Public Utilities Act*
Revised Statutes of Yukon, 2002, c. 186, as amended

and

An Application by Yukon Electrical Company Limited
For Approval of Revenue Requirements for 2008 and 2009

REASONS FOR DECISION

APPENDIX A TO BOARD ORDER 2009-2

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1 INTRODUCTION

On April 30, 2008, Yukon Electrical Company Limited (YECL) filed with the Yukon Utilities Board (Board) an Application, pursuant to the *Public Utilities Act* (Act) and Order-in-Council 1995/90, for approval of its forecast revenue requirements for the 2008 and 2009 test years and approval of certain deferral accounts (Application).

YECL is a wholly owned subsidiary of ATCO Electric Ltd., a private, investor-owned utility which is a member of the ATCO group of companies. YECL distributes electricity to approximately 15,000 customers throughout the Yukon. The YECL distribution system is fed by power purchased from Yukon Energy Corporation (YEC). In addition, it maintains back-up generating plants in certain communities in the event of a power interruption. YECL also generates and distributes electricity in several remote communities through diesel generating plants.

YECL is seeking approval for the following:

1) A revenue requirement of $46,660,000 for 2008;
2) A revenue requirement of $47,902,000 for 2009;
3) To continue the existing deferral accounts for Purchase Power Flow Through Costs, Fuel Price Flow Through Costs and Costs for the Diesel Contingency Fund; and
4) New deferral accounts to cover the Increased Fuel Costs Associated with Pelly Crossing and an Income Tax Rate Variance Deferral Account.

The revenue requirement for 2008 represents an increase of $2,220,000 over the amount that would be recovered under existing rates and riders; for 2009, the revenue requirement represents an increase of $4,130,000. These amounts represent an increase of 5.9% in 2008 and 5.1% in 2009, but do not include fuel price increases as stated in Section 4 of the Application.

Further, YECL requested that certain affiliate costs associated with ATCO I-Tek Ltd. and ATCO I-Tek Business Services Ltd. — affiliates of ATCO Electric Ltd. — be reserved as placeholders until such time as the Alberta Utilities Commission (AUC) rules on those costs as part of the benchmarking process before the AUC.
The Applicant also sought an Interim Rate Rider (Rider R), and Temporary Refund/Surcharge Rider (Rider G). These riders were to apply to all rate classes for YECL and YEC retail customers, except for Secondary Energy Rate 32 and Industrial Primary Rate 39.

In Board Order 2008-4, dated May 16, 2008, the Board ordered YECL to publish a Notice of Application and pre-hearing conference no later than May 23, 2008, in such appropriate local news publications in YECL's service area. YECL was also ordered to make the application and supporting materials available for inspection at its Whitehorse office at 100-1100 First Avenue and at the Watson Lake and Haines Junction public libraries.

On May 20, 2008, the Minister of Justice authorized the Board to incur the expenses necessary to conduct a public hearing into the Application pursuant to Section 50 of the Act.

The Board held a pre-hearing conference on June 12, 2008, in Whitehorse, at which time the Board heard submissions from parties on the following matters:

a) Issues List
b) Intervenor and Observer Status
c) Hearing Cost Process
d) Proceeding Schedule
e) Hearing Process
f) Interim Application

On June 20, 2008, the Board issued Order 2008-5, in which Intervenor status was granted to:

- Yukon Energy Corporation (YEC)
- City of Whitehorse (CW)
- Utilities Consumers' Group (UCG)
- Yukon Conservation Society (YCS)
- Department of Energy, Mines and Resources, Government of Yukon
- John Maissan, Leading Edge Projects Inc. (LE)

Observer status was granted to Paul Kishchuk, Vector Research. This Order also established a Proceeding Schedule for the Application and the Issues List. In addition, the Board directed YECL to file additional information as described in the Order.

Board Order 2008-6 approved an increase of 5.0% to existing primary base rates to be applied effective August 1, 2008, in the form of Interim Refundable Rider R. The Board denied the request for Rider G.

The Proceeding Schedule was further revised with Board Order 2008-7 when YECL requested additional time to provide responses to Information Requests (IRs) given the large volume of IRs. In addition, Board Order 2008-9 ordered YECL to provide further and better IR Responses in accordance with the Reasons attached in Appendix A to the Order by the close of business on September 15, 2008. The Board also allowed an additional round of IRs on depreciation through Board Order 2008-11.

On October 7, 2008, the Board held an oral public hearing in the City of Whitehorse, Yukon, before the Board comprised of Chair Wendy Shanks, Vice-Chair Robert Laking, and members Richard Hancock, Jody Woodland, and Kathleen Avery.

The Board directed the parties to file final argument by October 27, 2008 and reply argument by November 10, 2008. The Board considers the evidentiary portion of this proceeding closed as of November 10, 2008.

In reaching the determinations contained within this Decision, the Board has considered all relevant materials comprising the record of this proceeding, including the evidence and argument provided by each party. Accordingly, references in this Decision to specific parts of the record are intended to assist the reader in understanding the Board's reasoning related to a particular matter and should not be taken as an indication that the Board did not consider all relevant portions of the record with respect to that matter.

2 DISCUSSION OF ISSUES

2.1 Sales and Revenue

YECL forecast total primary sales to increase 0.8% in each of 2008 and 2009 while wholesale sales were forecast to remain at their current level of 488 MWh. Secondary sales were forecast to decrease by 28.5% in 2008 and a further 58.7% in 2009. The reduction in secondary sales was primarily due to the reduced availability of surplus hydro as a result of YEC sales to the Minto Mine.

The revenues associated with the energy forecast, including the proposed rate increases, are projected to be $45.8 million and $47.1 million respectively for 2008 and 2009.

FORECAST[1]	Actual 2007	Forecast 2008	Forecast 2009
Primary Sales (MWh) Growth Rate (%)	267,698	269,913 0.8	272,054 0.8
Secondary Sales (MWh) Growth Rate (%)	23,566	16,853 -28.5	6,954 -58.7
Total Company Sales (MWh) Growth Rate (%)	291,752	287,255 -1.5	279,497 -2.7
Total Revenues from Existing Rates[2] ($000) Growth Rate (%)	40,177	39,970 -0.6	39,557 -1.3
Total Revenues from Proposed Rates ($000)		45,850	47,075
Rate Increase from Existing Rates ($000) Less: Impact of higher Fuel Costs (Recovered through Rider F) Net Rate Increase from Existing Rates ($000)		5,881 (3,661) 2,220	7,518 (3,388) 4,130
YECL Primary Retail Revenue YEC Primary Retail Revenue Total YEC/YECL Primary Retail Revenue		33,677 3,795 37,471	33,937 3,750 37,687
% Rate Increase over Existing Rates		5.9	11.0

2.2 Forecast Process

YECL's forecast process involved a review of historic sales data by customer class and took into account the most recent information available at the time the forecast was prepared. YECL obtained the information through its work in the community and consultations with CW, Government of Yukon and local developers. In its Application,

[1] YECL 2008-2009 General Rate Application, Schedule 2.1; growth numbers have been calculated
[2] Includes YEC Revenue Shortfall (Rider J)

YECL indicated that the secondary sales forecast mainly came from YEC as YEC was responsible for determining the forecast availability of surplus hydro.

The sales forecast was prepared by customer class: residential, commercial, street and sentinel lighting, secondary and wholesale (sales to YEC). Intervenors took issue with what was felt were conservative sales and revenue forecasts made by YECL.

LE in argument stated that a great deal of detailed work went into preparing the sales forecast as outlined in the Application. Further, LE pointed out that information on the record indicated — for example, for the years 1996, 1997, and 2003 to 2007 — that YECL had underestimated their sales forecast. Despite this, LE concluded that the forecast should be accepted as filed.

YEC and CW recommended that the Board not approve YECL's sales forecast. Additionally, YEC did not support LE's recommendation to monitor YECL sales revenue forecast for future consideration.

Acknowledging YEC's point that YECL's actual sales had exceeded its internal business plan forecasts for prior years, YECL argued that the level of scrutiny and detail used to formulate YECL's internal business plan forecasts was nowhere near as rigorous or comprehensive as was used to derive the current General Rate Application (GRA) quality forecast. Further, the internal business plan forecasts were not the result of any statistical analysis and any comparisons made to the non-test year actuals by YEC were inappropriate and unfair. In summary, YECL submitted that the forecasts in its Application must be judged based on the evidence provided on the record and not on the attempt by YEC to derive a comparison that simply does not exist.

Views of the Board

The Board acknowledges YECL's submissions in argument that it had conducted extensive due diligence in respect of preparing its GRA quality forecasts as well as providing a large amount of documentation in its filing. Further, the Board understands that YECL's level of scrutiny and detail used to formulate YECL's internal business-plan forecasts is not as detailed as was used to derive the current GRA forecast.

However, the Board is concerned with the lack of evidence on the record regarding past YECL sales forecasts. The Board notes that the sales forecasts in evidence indicate that YECL's actual sales exceeded its GRA forecast by 3.9% and 1.5% for the years 1996 and 1997 respectively.[3] Further, regarding YECL's internal business plan forecasts for the years 2003 to 2007, the Board notes that the actuals exceeded forecasts within the range of 1.4% to 4.1% over the period.[4]

In considering the evidence regarding YECL's sales revenue forecast in the following sections, the Board will take the above into consideration.

[3] YEC-YECL-2(e) REVISED; dated September 15, 2008
[4] Exhibit C1-18

2.3 Residential Customer Sales Forecast

The residential sales forecast has two key inputs: the net customer additions and the average use per customer (UPC). The energy sales forecast is obtained by multiplying the forecast number of customers by the average UPC forecast.

Energy sales to residential customers are expected to rise 1.3% and 1.1% respectively in 2008 and 2009. YECL's customer count grew by 1.8% in 2006 and 2.1% in 2007 and is forecast to continue in this range with increases of 1.9% and 1.1% in 2008 and 2009 respectively.

2.3.1 Residential Customer Additions

In its argument, noting that the average increase in residential customer additions from 2003 to 2007 was 229, CW submitted that there was no detailed evidence to support YECL's substantial reduction to the growth rate of residential customers for 2009. Accordingly, CW submitted that the forecast residential customer growth rate for 2009 should be 1.9% (the same as 2008); thus, the residential customer increase for 2009 rises to 241 from 143 and at the same time the average number of customers rises from 12,836[5] to 12,934.

YECL replied that CW was dismissive of the facts presented by YECL, which materially affect its sales forecast, without providing any reason for dismissing such evidence. For example, with respect to the forecast number of residential customers for 2009, CW rejected YECL's evidence that the lack of developed land in the Whitehorse area will impact its sales forecast. YECL submitted that the Board should accept its uncontroverted evidence in this regard. Further, YECL suggested that there was no basis to arbitrarily increase the number of customer additions as suggested by CW. YECL submitted that its forecast should be approved as it is based on an extensive examination of the factors impacting such growth and specific information related to expected customer additions.

Views of the Board

The Board acknowledges YECL's statements regarding the availability of developed land in the Whitehorse area and the affect it may have on its sales forecasts. However, the Board notes CW's submission that, respecting residential customer additions for the period 2003 to 2007, the average growth rate was 229 customers or 1.9%. The Board further notes that the average increase of residential customers throughout the period was lowest in 2004 when the increase was 191 or 1.7%.

After carefully weighing the evidence respecting the forecast and actual increases in residential customers on the record, the Board accepts YECL's proposal that the number of residential customer additions grow by 1.9% in 2008. However, the Board agrees with CW that YECL's evidence does not support its forecast for 2009 indicating a significant reduction in the growth rate of residential customers. The Board notes that during the period 2003 to 2007, a 1.7% growth rate is the minimum growth rate for increases in residential customers. Therefore, the Board finds, based on previous years'

[5] Application, Schedule 2.1, Line 2

growth in residential customers, that the number of residential customers will increase by 1.7% in 2009. This 1.7% increase takes into account YECL's projections at the time of filing that there may be a shortage of developed lots in 2009.

Accordingly, the Board directs YECL in its refiling to adjust its 2009 forecast with respect to the number of residential customer additions from 1.1% to 1.7%. To be clear, the Board directs YECL in its refiling to increase the number of residential customers to 12,908 from 12,836 currently in the forecast and to reflect this change in related schedules and its revenue requirement in the GRA.

2.3.2 Residential UPC

The average UPC for the test period was determined by taking a three-year average of monthly UPC by community. UPC was normalized for Whitehorse and Watson Lake area communities using a "Normal" temperature, which is defined as a 20-year (1988-2007) average Heating Degree Days for Whitehorse and a 12-year (1996-2007) average for Watson Lake. Intervenors took issue with the process used to determine the average UPC.

CW in its argument submitted that inconsistencies in the regression analyses raised concerns regarding the soundness of the analyses. First, not all of the communities had their UPC normalized and second, of the communities that had their UPC normalized, the Normal temperatures that were used were different. Respecting the R^2 values used in the regression analyses, CW in its argument, as well as in its reply argument, expressed concerns regarding the use of R^2 values, which were less than 0.7 and YECL's inconsistent approach to justifying the levels of R^2 used in the Application. In conclusion, CW proposed a trend-line analysis[6] and submitted that its analysis was simpler and more trustworthy than the YECL analysis.

YECL replied that the use of 12-year versus 20-year data in no way materially alters YECL's forecast results and certainly does not diminish the validity or accuracy of the methodology used. YECL submitted that it would be highly inappropriate for the Board to abandon the consistent and previously accepted approach adopted by it in developing a sales forecast in favour of convenient "trends" that are not in fact based on any long-term data, and which only serve to fulfill CW's predetermined objective. YECL has clearly shown that weather affects residential sales.

Views of the Board

The Board acknowledges that YECL performed a great deal of detailed analyses to arrive at its sales revenue forecasts as outlined in the Application. However, the Board is not convinced that a more simplified approach could not achieve reasonable results with far less effort and cost to ratepayers. Therefore, the Board directs YECL at the time of its next GRA to include comparisons of its analyses and the analyses undertaken by other utilities in Canada to arrive at sales revenue forecasts.

[6] City of Whitehorse Argument

The Board has concerns with the range of R^2 values used throughout the analyses and YECL's justification for the wide range of values. Accordingly, the Board directs YECL at the time of its next GRA to include a detailed study as to what other jurisdictions consider a minimum value for R^2 that is acceptable in regression analyses.

Additionally the Board notes YECL's use of one variable in its regression analyses and the wide range of R^2 values in YECL's regression analyses. It is unclear to the Board whether or not the use of one variable in regression analyses is a contributing factor to the wide range of R2 values. Consequently, the Board directs YECL to undertake a study that compares the types of regression analyses — for example, univariate or multivariate — that other utilities may use in order to arrive at their analyses.

Considering the range of R^2 values and the lack of evidence as to what constitutes an acceptable R^2 value, the Board is not convinced that the residential UPCs as calculated are reasonable. The Board is of the view that a 2% increase in YECL's residential UPC is reasonable as it appears to be the low end of the variance where actual residential UPCs exceed forecast YECL residential UPCs. Therefore, the Board directs YECL in its refiling to increase its residential UPC by 2%, and to reflect this increase in all related schedules and its revenue requirement for the test years.

2.3.3 Commercial Sales Forecast

In the Application, the forecast UPC for existing commercial customers, except as noted in the Whitehorse area, was determined by taking a three-year average of monthly UPC by community. YECL based its Whitehorse commercial customer UPC forecast on the 2007 weather-normalized and adjusted UPC. YECL indicated that use of 2007 forecasts captures the impact of the larger commercial customers who came online in 2005, 2006 and 2007. Additionally, the Whitehorse 2007 UPC was adjusted to remove load specifically attributable to the Canada Winter Games.

Increased sales to the commercial class were due primarily to new commercial customers. Customer additions were forecast to increase by 1.1% in both 2008 and 2009. YECL anticipated most of the new commercial customers in its forecast to be running at or below the average UPC, keeping the growth in energy sales to a modest 0.4% and 0.5% in 2008 and 2009 respectively.[7]

In response to CW-YECL-15(d), YECL provided three reasons for the 1.4% reduction in commercial UPC between 2007 and 2009:

- Several new customer additions in 2008 and 2009 with lower than the 2007 annual average would bring down the overall average;
- The three-year average historical UPC used as the 2008 and 2009 UPC forecast for existing customers outside of Whitehorse was lower than the 2007 actual UPC; and
- The Whitehorse UPC based on the 2007 weather-normalized UPC and adjusted for the one-time load attributable to the Canada Winter Games resulted in a reduced Whitehorse normalized commercial average UPC forecast.

[7] Application, page 2-4

Having concerns with YECL's response to CW-YECL-15(d), CW in its argument indicated that without the detail required to support these forecasts, serious doubt was cast on the UPC forecast for 2009.[8] CW further pointed out that the one-time Canada Winter Games adjustment did reduce the Whitehorse normalized commercial average UPC in 2007, but was not significant enough to change the upward trend in commercial UPC in Whitehorse for the period from 2003 to 2007. CW stated that the three-year historical commercial UPCs were lower than their 2007 actual UPCs because the commercial customers outside the city of Whitehorse had UPCs that had trended upward for the years 2005 to 2007. In conclusion, CW submitted that YECL's downward trending commercial UPC forecasts for 2008 and 2009 are unpersuasive as the explanations provided in CW-YECL-14(d) and YEC-YECL-2(j) were general in nature, unconvincing and misleading.

YECL in reply argued that the fact that customer-specific information was not provided on the record does not detract from the validity of the positions presented by YECL in its evidence. Further, YECL submitted that the use of a three-year commercial UPC was common practice, was previously used and approved in the 1996-97 GRA, and should be accepted by the Board.

Views of the Board

The Board is not convinced that there is justification for the proposal by YECL to level off or reduce CW's UPC for the test period. The Board notes that UPCs for the commercial customers outside the city of Whitehorse, for the most part, have been increasing over the period 2005 to 2007. Therefore, the Board is not persuaded that the use of a three-year average justifies a decrease in commercial average UPCs for communities outside of Whitehorse. Further, the Board has concerns with the lack of data that forms the basis of the small load commercial customers connected to the system in 2009. The Board has concerns with the difficulties that YECL experienced in obtaining monthly UPC data[9].

Considering the above, the Board finds that the commercial UPC forecast should be increased. The Board finds an increase of 2%[10] is reasonable for the test years; 2% is in the lower range of values that represents YECL's consistent under forecasting and sales revenues. Accordingly, the Board directs YECL in its refiling to increase its commercial sales forecast by 2%. To be clear, the Board directs YECL in its refiling to increase its 2008 and 2009 MWh sales per customer[11] to 55.7 and 55.3 respectively.

Further, the Board directs YECL in its next GRA to provide a comparative study as to the analyses other utilities make use of to derive sales-revenue forecasts. The study should answer, but is not limited to, the following: What is the predominant methodology for forecasting sales revenues, i.e. averaging techniques, regression analyses, other? If averaging is used, what length of interval to average over is recommended and why? If

[8] Detailed information on the new customers cannot be provided due to customer confidentiality; CW-YECL-15(d)
[9] YEC-YECL-2(j).
[10] The forecast range can be referenced in YEC-YECL-2(e) Revised, September 15, 2008 and Exhibit C1-18.
[11] GRA Application, Schedule 2.1

regression analyses are used, how many variables account for the variability, what value of R^2 is valid, what are other relevant statistics?

3 PURCHASE POWER

Purchase power costs included in the Application were expected to remain relatively flat for the test period:

Description[12]	Actuals ($000)		Test Period ($000)	
	2006	2007	2008	2009
Primary Purchase Power	17,227	17,436	17,790	18,003
Secondary Purchase Power	1,130	1,194	1,028	424
Shortfall Rider J	4,882	5,017	5,028	5,067
Total Purchased Power	23,239	23,647	23,846	23,494

Approximately 90% of the power supply required by YECL is purchased from YEC. The purchases are for YECL's customers on the Whitehorse-Aishihik-Faro (WAF) and Mayo-Dawson (MD) grids. The amounts included in the Shortfall Rider J are related to YEC's Shortfall Rider J and are a flow-through for YECL.

YECL requested approval of two deferral accounts. The first deferral account is related to increases or decreases to the cost of purchased power, which was based on YEC's rates that were in place for primary energy and secondary sales[13]. YECL indicated that subsequent increases or decreases to these rates would be flowed through to YECL's customers. YECL also requested the continuation of the Diesel Contingency Fund (DCF) mechanism as approved in the 1996-97 GRA.

In its Application, YECL stated that Fish Lake hydro generation throughout the test period was based on the average generation over the last 10 years and adjusted for estimated downtime in the test period for required rebuilds. Intervenors took issue with the basis of YECL's Fish Lake hydro generation forecasts as well as the expensing of purchase power costs associated with the Fish Lake hydro rebuilds.

In its argument, YEC indicated that the DCF as established in the 1996-97 GRA settlement (Ex.C1-11, Tab 5) directed that "Rates and the fund will be determined using the long-term average water expected to be available for generation". YEC pointed out that the forecast Fish Lake generation (6.8 GW.h) at Fish Lake throughout the 2008 and 2009 test period was 3.8 GW.h below that which was forecast in the 1996-97 GRA and compared with 2007, the Application forecasts a reduction 2.8 GW.h in each test year.

YEC recommended that the Board direct YECL to adjust its Application so that Fish Lake hydro generation reflects the Fish Lake hydro long-term average water expected to be available for generation. YEC further recommended that the long-term average be

[12] YECL 2008-2009 General Rate Application, page 3-1
[13] YECL 2008-2009 GRA Application; Schedule 3.1, lines 6 and 7

based on all years of available data and not, as was done in the Application,[14] based on the last 10 years on record.

Contrary to YEC's argument, LE submitted that YECL should use a Fish Lake generation forecast that reflects recent practice, 6.962 GW.h per year, and that any generation below this actually experienced due to the required rebuilds should be clearly documented.

LE and YEC agreed and submitted in argument that YECL should be required to capitalize the purchase power required because of the Fish Lake Hydro rebuild. This would better reflect all relevant capital costs associated with the hydro rebuild and would avoid artificially raising test-year rates to recover added purchase power related to the Fish Lake Hydro rebuild.

In its reply argument, YECL indicated that relying on a 10-year average, adjusted for the planned rebuilds, was a reasonable approach considering the forecast output was higher than actual output in six of the last 10 years. Accordingly, YECL submitted that the forecast of purchase power, including the amount of generation from Fish Lake, was reasonable and appropriate for the test years and should be approved by the Board, as filed. With respect to the capitalization of purchase power costs associated with the Fish Lake rebuilds, YECL in its reply argument, submitted that it had followed a standard methodology in determining that these costs should be expensed and this approach should be approved by the Board.

Since there was little debate concerning the deferral accounts, YECL in its reply submitted that these deferral accounts should also be approved as requested.

Views of the Board

The Board acknowledges that enduring benefits will be provided to the facility and ratepayers as a result of the Fish Lake hydro rebuild. Further, the Board notes the capital costs associated with the rebuild are to be amortized over time due to the enduring benefits. The Board considered the YECL witness response that the incremental purchase costs from WAF related to the rebuild could be capitalized.[15] Therefore, the Board finds it reasonable to amortize the increased power purchase costs directly related to the rebuild project over time.

Further, the Board notes LE's argument that indicated that incremental power purchases incurred because of the required rebuilds should be clearly documented. The Board agrees that this is a reasonable approach. Therefore, the Board directs YECL in its refiling to capitalize the forecast purchased power costs associated with the Fish Lake rebuild and to not treat these costs as an expense item in the test years. The Board further directs YECL at the time of its next GRA to provide clear documentation of these incremental power purchases from WAF due to the Fish Lake hydro rebuild.

[14] The record that shows the basis for calculating the 10.042 GWh/yr average adopted in the 1996/97 GRA as well as the adjusted average when including the additional years of record now available; YEC Argument, page 13

[15] Transcript; pages 275 - 276

The Board acknowledges that there was little debate regarding the deferral accounts described in the Application, i.e. the Diesel Contingency Fund and Rate from YEC[16]. Therefore, the Board approves YECL's request for continuation of the aforementioned deferral accounts (see Footnote 16).

The Board is concerned with the YECL's proposed Fish Lake hydro generation forecast of 6.2 GW.h for each of the test years, which is a 3.8-GW.h reduction from the 10 GW.h of generation proposed in YECL's last GRA. The Board notes that YECL's statement that the 10-year average for Fish Lake generation of 7 GW.h is higher than the actual output in six of the last 10 years[17]. However, the Board notes that the average generation for the years when output exceeded the 7 GW.h, the average generation for the four years was almost 9 GW.h.

In making a determination on this issue, the Board considered YECL's submission in argument that it is in a new water-licence period and is subject to certain restrictions. Further, the Board accepts YEC's suggestion that the available generation at the Fish Lake hydro plant should be based on all years of available data. Accordingly, the Board finds 8.73 GW.h[18] is reasonable as the base generation for the Fish Lake hydro facility, prior to considering the impact of any downtime due to the Fish Lake hydro rebuilds. Therefore, the Board directs YECL in its refilling to reflect base hydro generation of 8.73 GW.h.

4 DIESEL FUEL COSTS

The following table[19] shows total diesel fuel costs included in the Application:

	Actuals ($000)		Test Period ($000)	
	2006	2007	2008	2009
Diesel Fuel Costs	2,026	2,054	5,715	5,299

The forecast diesel fuel cost increase of $3.6 million in 2008 is mainly due to the inclusion of the Rider F fuel rider in base rates for the test period.[20] The forecast diesel fuel cost decrease of approximately $0.4 million in 2009 is due to reduced diesel generation in Pelly Crossing because of its interconnection to the WAF grid. YECL is seeking continuation of Rider F as well as a deferral account for the incremental costs associated with a change to the assumption that Pelly Crossing's connection to the WAF grid would be effective November 1, 2008.[21]

In its argument, LE pointed out that YECL has not proposed conservation or efficiency programs in its diesel communities despite incurring diesel fuel costs greater than $5 million in 2006 and 2007. In light of the high diesel fuel costs, LE and YEC submitted

[16] GRA Application; page 3-2
[17] YUB-YECL-05 Attachment 1.xls
[18]
[19] YECL 2008-2009 General Rate Application, page 4-1
[20] Prior to 2008, YECL recovered the difference between the forecast 1997 fuel rates and the current fuel rate using Rider F.
[21] Pelly Crossing deferral account basis shown in the Application, page 4-3

that YECL should be directed to initiate energy conservation and efficiency programs in its isolated communities.[22]

In respect of the proposed Pelly Crossing deferral account, LE and YEC argued that if the Board were to approve the deferral account, any delays in connecting Pelly Crossing to the WAF grid should be clearly documented and justified. Additionally in its argument, YEC submitted that the Board should seek clarification from YECL with respect to how the Pelly Crossing deferral account would provide benefits to ratepayers, should it be connected to the grid earlier than November 1, 2008.

In its reply argument, YECL stated that it was always amenable to participating in conservation programs albeit YECL's experience has been that such energy conservation and efficiency programs have typically been led by a government-based entity. With respect to the Pelly Crossing deferral account, YECL indicated that the requested deferral account clearly meets the standard criteria for the approval of such a mechanism and accordingly submitted that the deferral account should be approved, as requested.

Views of the Board

With respect to the proposed Pelly Crossing deferral account, the Board notes that the typical criteria used in determining whether to approve the use of a deferral account are the level of uncertainty regarding the accuracy of the forecast and the utility's ability to control the factors influencing the forecast. The Board agrees with YECL that the Pelly Crossing deferral account meets the standard criteria and is reasonable and appropriate.

The Board agrees that YECL's proposal to continue a diesel fuel price rider deferral account, in order to address differences between forecast and actual fuel prices, is reasonable and appropriate. Therefore, the Board approves YECL's proposal for a diesel fuel price rider.

5 OPERATIONS AND MAINTENANCE EXPENSES

For 2008 and 2009, YECL has requested approval of operations and maintenance expenses (O&M) totaling $8.8 million and $9.3 million respectively. The Board notes the actual O&M for 2006 was $7.0 million while actual O&M for 2007 was $7.3 million

5.1 Labour Costs

In regard to labour costs, YECL indicated that it had to respond to competitive market forces (i.e. the tight "south of 60" labour market, and the reluctance of people to move to the north when high-paying jobs are available in the south) by developing and offering a compensation package that provided a fair compensation.

Expectations were that an average job-class wage increase of 9.5% for 2009 would result from the fall 2008 negotiations.[23] For the test period, this agreement also provided

[22] LE Argument, Page 9.
[23] The 2009-2010 collective agreement

wage increases related to certain job classifications that were technical in nature and mandatory to delivering safe and reliable service to customers. Additionally, commencing in 2009, YECL indicated that employees would also be entitled to additional travel benefits.

In argument, YECL stated that it had introduced programs that would assist it in attracting and retaining necessary resources, and its ability to provide safe and reliable service would be compromised if the cost pressures were not recognized and the associated O&M costs approved in its revenue requirement.

LE argued that YECL's staff remuneration proposals should be accepted but because of the significant increases, the approved FTE complement should be reduced. In its argument, YEC indicated that O&M labour cost increases from 2007 to 2009 equaled 36.7%, as compared with average annual increases of about 4.45% from 2003 to 2007. Further, YEC indicated that no requirement to pay the 9.5% existed in the collective agreement with YECL's employee association and the 9.5% figure was largely based on assumptions derived from remaining competitive with an Alberta-based market as opposed to a Yukon-based market.

YEC submitted that the Application had not provided sufficient evidence to support the 9.5% increase and recommended that the Board not approve a revenue requirement wherein the labour costs had yet to be negotiated.

In reply argument, YECL stated that it considered the information provided throughout the proceeding to be an accurate indication of what it would be required to pay under its own collective bargaining agreement for 2009. Further, YECL relied on the Sierra Systems to assist it in developing appropriate compensation measures that would assist it in remaining competitive in the marketplace.

In reply argument, YEC submitted that emerging market conditions suggested that caution should be taken in assuming that the tight labour market in western Canada would continue. YEC also submitted that a reasonable cap on overall O&M cost increases would avoid the need to interfere in the details of remuneration negotiations.

Views of the Board

The Board acknowledges the pressures that YECL has operated under with respect to maintaining its workforce complement, due to the tight labour markets in Western Canada in the past and the reluctance of people to move north. Although, as YECL stated in argument, no Intervenor took issue regarding the challenges that the utility faced with respect to securing and retaining qualified personnel over the past number of years, the Board must determine whether YECL has shown its forecast is reasonable.

The Board notes that YECL submitted the Application prior to entering into negotiations with its employee association. Further, the Board notes YECL employed the services of a third party to assist it in developing appropriate compensation measures that would help YECL retain its competitive position in the marketplace.

That being said, the Board has concerns respecting YECL's proposal for an average job-class wage increase of 9.5% for 2009 that YECL expects to result from the fall 2008 negotiations, considering the 22.5% increase in average compensation per FTE from 2007 to 2009. The Board notes that for the period from 2003 to 2007 the compensation increase was almost 18%, or 4.45% on average.[24] However, the 9.5% increase had not been negotiated at the time of the hearing. The Board is of the view that the tight labour market in western Canada is unlikely to continue seeing the emerging market conditions at the time of the hearing. As the Board considers the best available information at the time of the hearing, the Board is of the view that YECL has not shown that 9.5% increase in 2009 is reasonable. Rather the Board is of the view that the proposed increases for the test period are excessive. Further, the Board finds it reasonable to approve average annual compensation increases for the test period of 6.0%. Therefore, the Board directs YECL in its refiling to reflect a compensation increase per FTE of 6.0% for each of the years in the test period.

5.2 Vacancy Rate

YECL proposed a vacancy rate of 4.0% (2.25 FTEs) to be applied to all labour expenses for 2008 and 1.7% (2.0 FTEs) for 2009.

In argument, YEC stated that, given the fact that YECL had not been before the Board for a review in more than 10 years, the historic FTEs and vacancies that have occurred over that period are essential to understanding, on a go-forward basis, the relationship between FTEs and safe and reliable operation of a utility.[25] YEC further argued that no evidence is available that would provide assurance that the programs proposed by YECL to reduce vacancies would be successful or that the vacancy rates would be materially different than those experienced over the past decade. Accordingly, YEC recommended that the Board set YECL's O&M costs for revenue requirements based on the evidence regarding actual YECL average annual vacancy rates from 2003 to 2007.

In its argument, CW indicated that the average actual vacancies from 2003 to 2007 was 3.5[26]. Referring to YECL's response to CW-YECL-24, CW submitted that the downward pressure on the vacancy rates instituted by the Community Skills Premium would be offset by upward pressure created by employees wanting to work for other prominent companies in the north that offer superior benefits. Accordingly, CW submitted that the Board should rule that the FTE vacancy rate be 3.5 for both 2008 and 2009. YEC agreed with CW's recommendation.[27]

In its argument, LE submitted that YECL's FTE be approved as 55.43 in 2008 and 2009, and that the approved vacancy rate should be 1 FTE. LE further argued that if YECL's Automated Meter Reading (AMR) project was implemented the number of FTEs should be automatically reduced by one.

[24] Exhibit C1-14; YEC Argument, page 21
[25] YEC Argument, page 22
[26] City of Whitehorse Argument, Section 5.0, Vacancy Rates; Undertaking document, page 7 of 212
[27] YEC Reply, page 22

In reply argument, YECL indicated an average vacancy-rate approach, if adopted for the test years, would ignore the extensive programs that YECL had implemented in order to address its resource requirements and the success of these programs. Further, contrary to CW's evidence, YECL's enhanced efforts and increased benefits are working as it has been able to fill the vacancies previously experienced. Therefore, YECL submitted that its forecast vacancy rate was reasonable and appropriate given the current circumstances and should be approved by the Board, as filed.

Views of the Board

Because of the lack of evidence in support of the vacancy forecast, the Board finds that YECL has not met its burden of proof and is not approving YECL's proposed FTE vacancy rate forecast. The Board agrees with YEC that there is no assurance that vacancy rates will be materially different than those experienced over the past decade. Considering the above, the Board finds a vacancy rate of 3.5, the average actual vacancies for the period 2003 to 2007, to be reasonable for the test years. Therefore, the Board directs YECL in its refiling to reflect a vacancy rate of 3.5 FTEs for each of the test years.

5.3 Non-Labour Costs

YECL forecast non-labour costs in two parts: (i) ongoing operational and administrative activities (O&A), and (ii) new programs or projects. For non-labour costs, YECL proposed that an Alberta-based inflation rate of 5.0% be applied for each of the test years. In the Application, YECL explained that ongoing O&A are based on historic spending requirements which are then adjusted for known changes in work to be completed in the forecast period.

In its argument, YECL iterated that Alberta rates remain appropriate as this is the location of YECL's parent company, from which it acquires a number of services and materials. Furthermore, YECL stated in response to YEC-YECL-9 that it had experienced inflationary increases at least as high as the Alberta inflation rate. Given that the year-on-year inflation rate to August 2008 was 4%, YECL submitted that its forecast for other inflation was reasonable and appropriate and should be approved as filed.

In argument, LE suggested, in consideration of the global economy, that it did not seem reasonable to source everything from the highest cost province. LE submitted the 5% inflation rate was inappropriate now with the global financial crisis and rapidly declining commodity prices.

Likewise, YEC suggested that a Yukon-based inflation rate would appear to be the most relevant inflation rate for a utility operating within the territory; this would provide for a 2.5% inflation rate. Further, in argument, YEC pointed out that "… YECL selected the highest year-over-year inflation rate since 1988 for any of Canada, Alberta, Whitehorse, and British Columbia ..." [28] YEC recommended that the Board set YECL's O&M costs for revenue requirements based on the 2.5% inflation rate reported for the Yukon.

[28] YEC Argument; page 24

CW submitted in argument that the average increase for non-labour costs for the period 2004 through 2007 was 5.4% while for 2008 and 2009 it was 10.15%, a significant increase. CW further submitted that the 2008 and 2009 inflation rate for non-labour costs should be 3.25% based on a 50/50 weighting of the August 2007 to August 2008 Alberta CPI (4%) and the 2007 Whitehorse CPI (2.5%).

In reply argument, YECL stated that the local rates for Whitehorse, or macro-level rates for Canada, that fall below the 5% rate being utilized by YECL were not appropriate in the current circumstances. YECL indicated that the 5% rate used in the Application was still viewed as a reasonable rate for the two-year test period, given that the year-on-year inflation to August 2008 was 4%. Accordingly, YECL submitted that its forecast for other inflation was reasonable and appropriate and should be approved.

Views of the Board

The Board has concerns with approving YECL's proposed inflation rate of 5%, given that it was an Alberta-based rate and the year-on-year inflation rate to August 2008 was 4%. The Board further notes that the proposed 5% inflation rate represents the highest year-over-year inflation rate, i.e. Canada, Alberta, Whitehorse or British Columbia, since 1998.[29] Accordingly, the Board does not accept YECL's proposed 5% inflation rate for the two-year test period, as YECL has not shown it is a reasonable inflation rate.

Recognizing that YECL purchases a quantum of goods and services outside of the Yukon, the Board does not agree with YEC's recommendation to approve YECL's O&M costs for revenue requirements based solely on a Yukon inflation rate of 2.5%. The Board notes CW's suggestion regarding a hybrid inflation rate comprised of Alberta and Yukon CPI rates.

The Board finds it reasonable that the forecast non-labour inflation rate for 2008 and 2009 be 3.75%, which is calculated using a 50/50 weighting and inflation rates of 5.0% (Alberta) and 2.5% (Whitehorse).[30] The Board therefore directs YECL in its refiling to reflect in its revenue requirement, an inflation rate of 3.75% for its O&M costs other than labour.

The Board shares CW's concerns as to whether or not CPI is the appropriate inflation index to apply to the basket of goods and services purchased by YECL. Accordingly, the Board directs YECL in its next GRA to provide a study that compares what other utilities use as a basis for non-labour inflation rates.

[29] YEC-YECL-9(d)
[30] YUB-YECL-8(f)

5.4 Affiliate Costs

YECL out-sources certain major administrative functions to affiliate companies such as ATCO Electric (AE) to take advantage of the economies associated with the scope and scale of services available from a larger utility. In its Application, YECL indicated the costs of these services to be based on a fully allocated cost methodology that does not contain any element of profit or return.

Further, in addition to labour support provided from AE, YECL purchases information technology and billing system services from ATCO I-Tek and ATCO I-Tek Business Services respectively. YECL explained that these services were being reviewed as part of a benchmarking process and that a final report was to be filed by ATCO with the AUC. YECL stated that it would update the placeholders included in this Application once the appropriate reports had been finalized and approved by the AUC.

During the hearing, YECL indicated that the I-Tek costs were developed from the costs filed before the Alberta Energy and Utilities Commission (EUB) as part of a benchmarking study. When questioned by CW as to why YECL did not regard the rates in the Application as placeholders, to be changed at the time that those rates were fixed in Alberta, YECL's witness stated:

> Again, given the exposure to more proceedings, given that I-Tek – the I-Tek does mirror the I-Tek rates that are in the benchmark report, because it is the same services for I-Tek that Yukon Electrical receives – that ATCO Electric receives. I do appreciate that there is an ongoing process, but to put it in perspective, from an ATCO position, we think the rates are final. Agreed they're not approved, so there could be some adjustments, but we're looking at $300,000 in costs for Yukon Electrical compared to around $50 million of I-Tek costs for the ATCO Utilities. So within that $50 million, that number could change slightly. It's been a four-year process. I don't think it's going to be substantive, but there could be some slight changes. We felt that, rather than let Yukon Electrical get wrapped up in another process, the substantive savings have been captured and are reflected in this filing[31].

In argument, CW indicated that it was prepared to accept YECL's explanation concerning why the Evergreen[32] rates were not employed, i.e. that YECL received different billing services from I-Tek than does AE or ATCO Gas.

Further, notwithstanding this limited acceptance, CW indicated that it was not satisfied that the Alberta CPI rates of inflation used to inflate the benchmarking costs on an annual basis were appropriate. CW opined that information processing costs change at a different rate than the general CPI basket.

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[31] Transcript Volume 3, October 9, 2008 page 311 lines 15-26 inclusive.

[32] A term used by CW in its Argument under the section for Affiliate Costs (page 20) which refers to a benchmarking process respecting IT and customer-care services that is ongoing before the Alberta Utilities Commission (AUC) in Alberta and involves such ATCO-regulated affiliates as ATCO Electric (AE) and ATCO Gas (AG) and the unregulated company known generically as ATCO I-Tek which provides the IT and customer-care services. The final decision on this AUC process will form the basis of costs from the unregulated entity (I-Tek) to the regulated companies (AE and AG) when the study is completed.

Although it might be more exact to use a placeholder for I-Tek rates, CW considered that it would be more efficient from the regulatory standpoint to accept these rates as final for setting YECL's rates. Finally, CW submitted that the Board should order YECL to file for information purposes the final I-Tek rates that result from the Evergreen process and the difference it would have made for revenue requirement for each test year once the Evergreen process is completed.

Views of the Board

The Board finds CW's proposal to accept these (I-Tek) rates as final for setting information technology and customer care rates appropriate from an efficiency standpoint. Accordingly, the Board approves YECL's proposed affiliate costs subject to the proviso that the inflation rate will be adjusted to the Board-approved inflation rate for non-labour costs (see above Section 5.3). The Board directs YECL in its refiling to align its proposed affiliate costs with the non-labour costs adjusted to reflect the Board-approved non-labour inflation rate.

5.5 Taxes Other Than Income

In its Application, YECL provided actual property tax values for 2006 and 2007 and forecast values for the years 2008 and 2009. Increases in property taxes were said to be primarily due to inflation. "Property taxes are paid … annually for Yukon Electrical's office building, generation facilities, substation properties and power lines."[33] In its Application, YECL requested approval of $249,000 for Taxes Other Than Income for 2008 and $261,000 for 2009.

When questioned by Board counsel, YECL stated that the actual property tax rate for 2008 was 3.8%[34].

YECL was the only party to comment on this in argument where it said that the 7.5% increase for property taxes was the best information at the time and therefore the forecast amount should be approved.

In reply argument, YEC stated:

> … the Board should direct that YECL's application be adjusted to provide for a property tax rate increase in 2008 of 3.8%, with consistent adjustments made as required also to the 2009 property tax forecasts[35].

[33] Application, page 6-1
[34] Transcript volume 3, October 9, 2008 page 389 lines 20-30 inclusive
[35] YEC Reply, page 26

Views of the Board

The Board agrees with the position of YEC that the 3.8% increase for 2008 is the most accurate and up-to-date information in this proceeding. Therefore, the Board directs YECL to use 3.8% as the increase in Taxes Other Than Income for 2008 over 2007 actual costs. The Board accepts the 4% forecast increase amount over 2008 costs for 2009 costs as proposed by YECL.

5.6 Depreciation

5.6.1 Equal Life Group (ELG) versus Average Service Life (ASL) methodologies

Depreciation for 2008 and 2009 for YECL was based on a depreciation study by Gannett Fleming Inc. (the Study). The Study based the depreciation rates on the straight-line whole-life method using the equal-group life procedure.[36] Attachment 1 of Section 7 of the Application contains the Study. Part I explains the scope, Part II describes the Study, and Part III provides the results. Depreciation expense, through the Study was determined to be $4,365,000 for 2008 and $4,837,000 for 2009. The Study is a continuation of the methods and assumptions utilized by YECL in the past. The position of YECL is that the ELG method has regulatory acceptance in several jurisdictions and provides better matching of asset consumption to depreciation expense.

In its argument, YEC stated that for regulatory consistency and to reduce test-year costs for ratepayers, YECL should have considered adopting the ASL approach as well as followed the Future Reserve for Site Restoration directions from Order 2005-12.

YEC contended that the ASL method was widely accepted in Canadian regulatory jurisdictions, was a means to balance utility and ratepayer interests, and was accepted by the Board in Order 2005-12.[37]

YEC further submitted that rate stability is a consideration when determining a depreciation method and that such was a governing factor when choosing the method for YEC in its previous application.

LE was of the view that there was not enough evidence to suggest YECL should change the method of depreciation utilized.

In its argument, YECL stated that the depreciation method employed by YECL was the same method as previously utilized by YECL. YECL confirmed that it supports the expert evidence that Gannett Fleming provided. The YECL position is that the ELG method is technically superior, widely accepted, complies with International Financial Reporting Standards, and should not be changed based on a criteria to reduce the test year revenue requirement.

[36] Application, Section 7 – Attachment 1, page 2 of 158
[37] From YEC Argument, pages 16-17 inclusive

CW supported the position of YEC (ASL method) in reply argument on the basis of regulatory consistency (the same method utilized by YEC) and the effect of lowering costs and the revenue requirement.

YEC maintained its position that YECL did not propose a depreciation method that is accepted in Canada and would reduce ratepayer costs. Further, it did not make a case that the use of ASL is inappropriate. YEC contended that the question of technical superiority of ELG versus ASL was of no relevance or assistance to the Board[38]. YEC submitted that consistent treatment of a depreciation method (the ASL method) is in the interests of current ratepayers and is not unfair to YECL.

LE said in its reply argument:

> … the short term benefits of the ASL approach would be outweighed by the future higher ratepayer costs when who knows what other cost pressures there might be. The ASL is likely to be short term gain for long term pain. The better intergenerational fairness and the reduction in depreciation expense actually being realized should make it easy to stay the course and continue to use the ELG approach[39].

In its reply argument, YECL said "… that it was YEC, against the recommendation of its expert witness, that sought changes to the depreciation methodology previously approved by the Board, which is indeed consistent with Yukon Electrical's treatment as proposed herein[40]." YECL further asserted that it was adopting the advice of its expert witness on the continuation of the depreciation method employed by YECL. Finally, YECL noted that the use of the ELG method was supported by LE.

5.6.2 Future Reserve for Site Restoration (FRSR)

The issue of FRSR did not appear in the Application. The topic did not come up until IRs were asked of YECL.

In argument, YEC said:

> In Order 2005-12, notwithstanding arguments to the contrary from Yukon Energy and YECL, the Board also directed Yukon Energy to discontinue recording its annual depreciation provision for Future Removal and Site Restoration ("FRSR") costs effective January 1, 2005 (which the Board estimated in its Order at $533,336), ordered a variance for Yukon Energy from Generally Accepted Accounting Principles ("GAAP"), and required that the December 31, 2004 balance in the FRSR account for Yukon Energy remain as a liability to be utilized for dismantling costs that are incurred in 2005 and future years[41].

YEC further stated, "that YECL should be subject to the same treatment regarding FRSR depreciation as directed by the Board with regard to YEC in Order 2005-12[42]."

[38] YEC Reply, page 29
[39] LE Reply, page 3
[40] YECL Reply, page 18
[41] YEC Argument, page 14
[42] YEC Argument, page 18

YEC got confirmation through YECL's response to YEC-YECL-II-2 that YECL has a form of FRSR[43] built into its depreciation rates and has a means for separately accounting for that amount. YEC contended that the arguments supporting the continuation of an FRSR item by YECL were parallel to those proposed by YEC in 2005 that were ultimately rejected by the Board. YEC added that the FRSR liability balance to the end of 2007 for YECL was $4,688,111[44] and that the annual costs of FRSR for the test years were $945,000[45] for 2008 and $1,003,000[46] for 2009. YEC asked that for regulatory consistency for both utilities (YEC and YECL) and to show reductions that benefit ratepayers, that YECL should cease recording any provision for FRSR effective January 1, 2008. Forecast depreciation expense, as determined by YEC, would be reduced by $945,000 in 2008 and by $1,003,000 in 2009.

CW submitted that there should be consistency among Yukon utilities for FRSR. CW recommended that the FRSR equivalent be separated to determine total negative net salvage in the reserve and allow the Board and Intervenors to seek if FRSR is reasonable or needs to be capped.

In its argument, YECL stated that based on the testimony of its expert depreciation witness, it is only aware of YEC and B.C. Hydro using an FRSR fund. YECL's position was that the collection of negative net salvage had long been approved by the Board and was a widely accepted practice across North America. Finally, YECL submitted, "that the recovery of net negative salvage through tolls best complies with the depreciation objective to recover the service value of assets over there [sic] estimated lives, and best complies with regulatory fairness[47]."

In reply CW stated:

> While CW considers that it is appropriate to collect certain future costs in the present, over-collecting negative net salvage through rates results in present customers paying the cost of future customers. If the actual cost of site restoration and remediation is less than what was collected in rates, intergenerational inequity will result[48].

Further, CW agreed with YEC in that the accumulated negative net salvage value should be capped as at the end of 2007 and amounts for 2008 and 2009 should be removed from the depreciation rates. It was CW's view that this would bring consistent regulation and result in lower regulatory risk.

Consistency between the two utilities was necessary from the reply of YEC. YEC also noted that it did not choose the method determined by the Board in Order 2005-12. YEC

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43 YECL's form of FRSR is known as negative net salvage
44 YEC-YECL-II-2(c) Attachment 2
45 Ibid
46 Ibid. The above two amounts $945,000 and $1,003,000 were net salvage for 2008 and 2009 respectively. To determine the ending balance for Accumulated Depreciation Net Salvage forecast net salvage amounts need to be removed. These amounts are -$113,000 and -$75,000 for 2008 and 2009 respectively.
47 YECL Argument, page 21
48 CW Reply, page 8

stated that YECL's arguments do not recognize that it was the Board that raised the FRSR issue in 2005 and decided that that was the approach to be taken in Yukon.

In its reply argument, YECL said that YEC is asking the Board to decide this topic based on a previous YEC proceeding and argued that if a decision was made on this basis, it could result in an error of law. YECL maintained that its treatment of negative net salvage was consistent with past practice, based on the expert testimony of its witness, and is widely applied across North America.

Views of the Board

The Board acknowledges that both the ELG and ASL methods are recognized in Canadian regulatory jurisdictions. Until 2005, both YECL and YEC utilized the ELG method when determining the amounts to be included in depreciation. The Board, with the exception noted below, finds that it is in agreement with the findings of the depreciation study undertaken by Gannett Fleming Inc. It is the Board's view that consistency is important and that it is not limited to methods employed across utilities but requires a consistent use of methodology within a utility. In this particular case, both YECL and YEC calculate depreciation and use depreciation expense to determine overall revenue requirement. YECL has demonstrated that it has consistently employed the same methodology. Therefore, the Board accepts the use of the ELG method by YECL.

With respect to FRSR, the Board is persuaded by the arguments of YEC and CW that consistency in this area is important. YECL responded that two critical facts were specific to YEC and those facts were not consistent with the circumstances of YECL: (1) YEC has recorded an Asset Retirement Obligation related to the legal requirement for the removal of facilities in compliance with Section 3110 of the CICA handbook; and (2) The company has recorded FRSR requirements into a separate balance sheet account[49]. The Board is of the view that the substance of the circumstance of YECL is similar to that of YEC. That is, YECL has a salvage obligation and YECL has the ability and can account for amounts equivalent to FRSR. Whereas both YECL and YEC utilized acceptable depreciation methods, the treatment of FRSR or negative net salvage is not consistent between the two utilities. Given that the negative net salvage balance continues to grow, the Board does not believe that there is a need to continue to collect such amounts. YECL is to remove these amounts[50] from its depreciation expense for each of the test years and is not to include any amounts for negative net salvage until Board approval is provided. Further, the Board orders that the December 31, 2007, accumulated amount for net negative salvage be shown as a liability and be reduced as salvage costs are incurred for the years commencing with 2008. Similar to YEC, YECL is to inform the Board and interested parties when the balance for this liability account reaches $2 million.

[49] YEC-YECL-17(g), page 4 of 6
[50] YECL is to remove from depreciation expense $945,000 for 2008 and $1,003,000 for 2009

5.7 Return on Rate Base

5.7.1 Cost of Capital

5.7.1.1 Capital Structure

YECL requested a capital structure consisting of 47.5%[51] equity. The derivation of the capital structure and the rate of return on equity is provided in Attachment 1 of Section 8 of the Application in a report prepared by Kathleen C. McShane (Ms. McShane) of Foster Associates (Foster Report).

The Foster Report described the parameters of the engagement with YECL as follows:

> Yukon Electrical Company Limited ("Yukon Electrical") has requested an expert opinion on fair return, comprised of both an appropriate capital structure and a return on equity (ROE) for the Company's 2008 and 2009 test years, using, for the express purpose of these two test years, the benchmark return on equity established by the Alberta Energy and Utilities Board (EUB) as a point of departure[52].

Without restating the Foster Report, the approach used "… is to assess the specific regulated company's business risks then establish a capital structure that is compatible with its business risks and permits the application of the cost of equity determined by reference to proxies to the specific regulated company without any adjustment to the proxy companies' cost of equity"[53]. This was determined through the following three principles outlined in the Foster Report[54]:

1. The Stand Alone Principle
2. Compatibility of Capital Structure with Business Risks
3. Maintenance of Creditworthiness/Financial Integrity

In terms of business risk, the Foster Report said that YECL:

- Is exposed to a significantly higher degree of business risk than the typical electricity distribution utility in Canada;
- Is of higher than average business risk within the spectrum of Canadian utilities; and
- Is of similar business risk to its sister utility in the Northwest Territories, Northland Utilities (Yellowknife) Limited[55].

Further conclusions in the Foster Report were:

- Capital structures of YECL peers imply that the equity ratio for YECL should be no less than 50%.

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[51] Application, page 8-2
[52] Application, Section 8, Attachment 1, page 1
[53] Application, Section 8, Attachment 1, page 4
[54] For a description of these principles and how they were applied to YECL, see Attachment 1 of Section 8 of the Application, pages 12 to 15 inclusive
[55] Application, Section 8, Attachment 1, page 22

- For YECL's business risk, debt rating agency guidelines suggest a capital structure of 45-55% equity.
- Financial metrics for YECL, with guideline ranges and comparisons for other electric utilities suggest an equity ratio for YECL to be in the upper end of the 47.5% to 52.5% range.
- Debt-rating agencies are commenting the equity ratios and returns for Canadian utilities are too low.

In argument, UCG stated:

> UCG submits that this stand-alone principle falls apart when rationalizing YECL's proposal for raising its equity to debt structure as well as receiving a higher rate of return for being a small stand-alone company. Evidence above shows that YECL does not go out and raise debt on its own, nor do they stand alone when doing business with affiliates and mother corporation.[56].

YEC argued that YECL's application violated several consistency principles. The requested increase in the equity component is, "… a material departure from the common equity ratios approved to date by the Board …[57]" YEC submitted that historically the equity ratio of YECL has been less than that of YEC and that the equity level and ROE as recommended by the Foster Report is higher than that of comparable Canadian utilities. YEC recommended that the equity ratio for YECL not exceed 40%[58].

CW refuted several of the business-risk assessments in the Foster Report. CW pointed out in its argument that the Minto mine was not a YECL customer and the secondary impact of a loss-of-mine load only comes after a lag. Further, CW cited the stability of the public administration sector in Whitehorse and the small amount of generation in YECL's asset portfolio as reasons to support a lower business risk assessment for YECL. In terms of comparing YECL to Northland Utilities (Yellowknife) Limited [NUL(YK)], CW noted that the last approved equity ratio for NUL(YK) was 40% and that YECL is nearly twice the size of that utility[59].

YECL reaffirmed the evidence of the Foster Report in its argument and noted that in Order 2005-12, the Board did not impose a precedent in Yukon when using the BCUC automated-adjustment mechanism. YECL noted that it argued against the BCUC automated-adjustment mechanism approach in YEC's 2005 application. The use of the BCUC, AUC or NEB approaches to determining the rate of return provided results essentially in the same range and YECL utilized this approach, "… as it would avoid an extensive debate over the appropriateness of using the traditional methods to determine return on equity …[60]"

YECL stated that the change in capital structure since their last time before the Board is, "… based on the changes that have occurred in the market and the conditions …[61]"

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[56] UCG Argument, page 3, point 18
[57] YEC Argument, page 35
[58] YEC Argument, page 39
[59] CW Argument, page 32
[60] YECL Argument, page 22
[61] Ibid, page 24

YECL further argued that the three principles utilized in the Foster Report are widely accepted and that:

> The fair return standard then requires that the combination of capital structure and ROE produce a return on capital which meets the three requirements of the fair return standard: these three requirements, the comparable returns standard, the financial integrity standard and the capital attraction standard[62] …

YECL reinforced its support for the stand-alone principle, stated that the capital structure and return should be maintained at a level similar to CU's high credit rating. A lower capital structure or return on equity would effectively create a cross-subsidization from CU Inc.

YECL summarized that it was a higher business risk than the typical electricity distribution utility in Canada and that the recommendation for capital structure was based on[63]:

1. Capital structures allowed for YECL peers with any risk premiums adopted;
2. Actual capital structures maintained by other utilities;
3. Guidelines for capital structure and A debt ratings set forth by debt-rating agencies; and
4. Analysis of the resulting financial metrics.

CW replied:

> In fact, Ms. McShane's recommendations result in an interest coverage that is well above the comparable returns of her own sample. Only the recommendation of CW of an ROE of 8.75% and an equity ratio in the 40-42% range results in an interest coverage ratio that is comparable to that of an average Canadian electric utility[64]. YEC also noted that YECL was unable to identify any business risks that exceed those for the average Canadian utility[65].

CW submitted that:

> … YECL has not established in evidence or provided any credible argument as to why its FFO interest coverage ratio should exceed the Canadian average and, therefore, why its equity thickness should lie outside the 40-42% range[66].

YEC replied that it agreed with CW in that YECL is less risky than YEC or NUL (YK). Assuming an ROE of 8.75%, YEC recommended an equity ratio that should be less than the range of 40-43%.

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[62] Ibid, page 25
[63] Ibid, page 26
[64] CW Reply, page 10
[65] Ibid, page 12
[66] Ibid, page 13

LE replied that in the past the Board has viewed YECL as a high-grade or low-risk utility[67]. LE recommended an equity ratio of 47.5% on a return of 8.75% or an equity ratio of 42.5% on a return of 9.25%.

YECL replied that the YEC arguments do not consider the evidence in the Foster Report and that the business-risk concerns raised by CW were part of YECL's assessment.

Views of the Board

In response to YUB-YECL-33(c), YECL responded:

> Yes, in principle Yukon Electrical would contribute to the size of CU Inc., and thus provide some small contribution to the size and diversification of the entity which provides its debt.

The Board interprets this response to mean that YECL also contributes (albeit in a small way) to the size, diversification and capital structure on AE. Given that capital in the form of either debt or equity flows to YECL through AE (or through CU), and that there is a strong management influence[68] on YECL through AE, and given the significant affiliated transactions and contracts between YECL, AE and other ATCO companies, this Board rejects the stand-alone principle in determining capital structure.

Responses to YUB-YECL-38(a) whereby YECL stated that YECL does not face a higher regulatory risk than a typical electricity distribution company in Canada and to YUB-YECL-34(e) where YECL stated that the ability to earn the allowed return is not a financial risk but a business regulatory risk give credence to the argument that YECL is not a high-risk utility.

The Board accepts the argument from CW that based on the equity ratio proposed by YECL the FFO[69] interest-coverage ratio is higher than that for other Canadian transmission or distribution utilities. The Board also accepts CW's argument that YECL has not satisfied the Board that YECL's business risks are higher than those of a typical distribution or transmission utility.

Further, in response to YEC-YECL- 40(c), YECL confirmed that YECL has operated at a capital structure of approximately 40-43% equity for the years 2003 to 2007. The Board is not satisfied that evidence has been placed before it which would warrant any upward movement in the equity ratio. Comparable evidence on equity thickness from CW-YECL-36(a) wherein EUB Decision 2004-052, the benchmark capital structure (equity) for electric transmission and distribution utilities is 33 and 37% respectively. CW-YECL-36(c) gives an equity ratio for Ontario distributors of 40%.

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[67] LE Reply, page 4

[68] Page 5-3 of the application describes the affiliate costs. Page 5-4 describes the affiliated parties, and Schedule 5-3 quantifies the costs. In addition YECL has adopted operational policies such as ROW Maintenance, and is proposing to use AE to implement an AMR system

[69] FFO – Funds From Operations

The Board considered the statement[70] in the Foster Report that YECL is of similar business risk to NUL(YK). Oral testimony from YECL confirmed that the actual equity ratio had been approximately 40% and that the last approved (based on a Decision in 2005) equity ratio for NUL(YK) was 40%[71].

The Board is not convinced that the YECL situation or risk profile has changed since its last approved equity ratio for 1997[72] to warrant a substantial increase in the equity ratio.

For these reasons, the Board cannot accept the equity ratio as proposed by YECL. Given current market conditions which are discussed in the Cost of Debt Section, the Board directs YECL to use the last approved[73] equity ratio of 40% which is similar to the more recent (2005) PUBNWT Decision for the equity ratio of NUL(YK).

Finally, in arriving at its finding on this issue, the Board did not consider comments in reply argument by CW and YEC relating to PUBNWT Decisions 24-2008 and 25-2008. The Board considers these comments as new evidence that had not been discussed at the hearing.

5.7.1.2 Cost of Equity

The cost of equity is strongly linked to the capital structure. This was the position of YECL and largely acknowledged by the Intervenors. As noted above, Attachment 1 of Section 8 contains the Foster Report which provides the recommendation for the cost of equity for YECL. YECL accepted the recommendation in the Foster Report, that is, a capital structure of 47.5 % equity and a return on equity (ROE) of 9.25%. Much of the evidence on cost of equity is contained in the Capital Structure section and will not be repeated here.

In argument, UCG submitted that the benchmark rate of return proposed in YECL's application be denied. UCG made a recommendation for an overall rate of return but did not make a recommendation specific to the return on equity.

YEC expressed the following concerns in its argument:

> More specifically, the approach adopted in the Application fails to follow past YUB practice with regard to determining a fair rate of return for YECL (based on Board decisions issued when YECL was previously reviewed by the YUB: 1992-1; 1992-2; 1993-8 and 1996-6), significantly deviates from the AUC benchmarking methodology which it "uses as a point of departure" for determining a fair return, and moves away from the approach utilized by YEC in 2005 to determine its return on equity during the Required Revenues and Related Matters hearing[74].

[70] Section 8, Attachment 1 - Foster Report, page 22.
[71] Transcript Volume 2, October 8, 2008. Page 169 lines 5 to 27 inclusive
[72] Board Order 1996-6, page 11 of 17, Schedule 4B.
[73] Board order 1996-6.
[74] YEC Argument, page 35

YEC argued that historically the Board has concluded that the business risk of YECL does not differ from that of a high-grade utility. YEC labeled the YECL approach as hybrid as it used a benchmarked rate from one jurisdiction and then made adjustments. YECL is a lower-risk utility when compared to YEC. YEC recommended that YECL use either the AUC benchmarked rate or the BCUC benchmarked rate plus premium (total return on equity would be 9.02%).

LE stated in argument: "A fair return on equity for YECL is probably lower for the proposed capital structure than is being requested"[75].

CW recommended in its argument a return on equity of 8.75%.

YECL stated in its argument:

> The proposal to base the ROE on the AUC formula rather than re-determining the ROE from first principles recognizes that (1) a formula ROE similar to the AUC's currently governs most of the major Canadian utilities and (2) the validity of the existing formulas is currently undergoing review in two major jurisdictions, before the NEB and the AUC. The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions[76].

In reply argument, CW reaffirmed its position that an ROE of 8.75% is appropriate.

YEC noted that although the formula-based approach is being review by the National Energy Board (NEB) and by the AUC, it was last reviewed by the BCUC in 2006 and hence is not under current review. YEC added that YECL stated the NEB, AUC and BCUC formulae within a range yield similar results. YEC recommended an 8.75% ROE with a deemed equity ratio of 40-43%.

LE did not accept YECL arguments that it is a higher risk than other Canadian utilities but did state that the recommendation made in its final argument is appropriate.

YECL disagreed with the position of YEC in its reply argument. YECL did state that it was prepared to accept a return of 9.14% based on the BCUC formula.

Views of the Board

The Board strongly agrees with the part of the YECL argument that states:

> The proposal to rely on the generic ROE as a point of departure was intended to be the most efficient means of addressing what is inherently a complex and costly matter, given the current state of ROE determination throughout Canadian regulatory jurisdictions[77].

[75] LE Argument, page 6
[76] YECL Argument, page 23
[77] YECL Argument, page 23

YECL covers a geographically dispersed area with a relatively small customer base. It is incumbent upon the Board to explore ways that yield regulatory efficiency and yet provide fairness to all interested parties. In this regard, the Board supports a formula-based approach to determining ROE issues. YECL used the AUC Generic Cost of Capital as its starting point while YEC supports the BCUC formula[78]. CW was also supportive of the BCUC generic cost of capital[79]. Both YECL and YEC have argued that reference to a formula approach is efficient from a regulatory efficiency perspective. To reference a generic cost-of-capital approach from another jurisdiction, the Board must answer the following questions:

- Which generic cost-of-capital model should be used and from which jurisdiction?
- Should a risk premium be applied?
- If a risk premium is applied, what risk premium level should be applied to YECL?

Which generic cost-of-capital model should be used and from which jurisdiction?

Of the three models discussed (NEB, AUC, and BCUC) the BCUC model has been the most recently reviewed and is not under current review. In reply, YECL said it was prepared to accept a return based on the BCUC formula. Therefore, the Board directs that the BCUC generic cost of capital is the most appropriate as it has been the most recently reviewed, and is generally accepted by the parties.

Should a risk premium be applied?

In Appendix A to Board Order 2005-12, the Board accepted YEC's recommendation of a risk premium of 52 basis points and noted that it was greater than the risk premium for FortisBC and less than the risk premium for Pacific Northern Gas. YEC argued that it was more risky than FortisBC since FortisBC had inter-tie connections with other utilities allowing more purchase power options and affording greater flexibility to its generation. The evidence in the Foster Report, although related to capital structure, also suggested a risk premium for YECL. The Board accepts that when using the BCUC generic cost of capital, a risk premium is required for Yukon utilities.

What risk premium should be applied to YECL?

In its reply argument, YECL suggested a risk premium of 52 basis points, the same as YEC. However, the Board notes that YECL acknowledges that relative to YECL, YEC has more risk[80]. The Board considered Appendix A of Board Order 2005-12 in finding that without the same inter-tie connections as FortisBC, YECL is more risky than FortisBC. As a result, the Board finds it reasonable to place the risk premium for YECL at the midpoint of the risk premiums between YEC and FortisBC — at 46 basis points. Therefore YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE.

[78] Appendix A to Board Order 2005-12, page 43. "Therefore, in their Application, YEC is proposing that the allowed return on equity be set by reference to the BCUC formula approach …"

[79] CW Argument, page 28 where CW stated: "For regulatory consistency with YEC, CW would have preferred that YECL use the BCUC generic cost of capital as the appropriate point of departure."

[80] Transcript Volume 2, October 8, 2008. Page 206 lines 4-7 inclusive

5.7.1.3 Cost of Debt

In its Application, YECL forecast an embedded debt cost of 7.01% for 2008 and 6.83% for 2009.[81] The embedded debt cost was calculated based on the weighted average of all debt issues. This included the actual existing historical debt issues plus the forecast amount and cost of debt to be issued in 2008 and 2009.

There was no controversy regarding the cost of the existing debt issues. However there was debate regarding the forecast cost of debt for 2008 and 2009.

Interest Rate Calculation Method

YEC took issue in argument with YECL's method of calculating the interest costs of new debt issued in 2008 and 2009. YEC indicated that YECL's method averaged the interest cost rate during the test year rather than taking into account the date that the new debt was expected to be issued. The Board notes that the Schedule 8.3 of the Application indicates that the new debt was forecast to be issued on November 20 of 2008 and 2009 and that debt in the past had often been issued on about November 20. In reply argument, YECL submitted that its mid-year rate-base method has been in place for decades and was consistent with the calculation of mid-year rate base, mid-year debt amount and mid-year work in process.

Views of the Board

The Board notes that YEC provided figures that indicated the impact of its proposed calculation method would lower the debt costs from 7.01% and 6.83% to 6.77% and 6.65% for 2008 and 2009, respectively. However, the record of the proceeding does not contain details of this calculation. Therefore, the Board did not consider this evidence as it had not been tested in the hearing.

The Board agrees with YECL that its mid-year method of calculation is consistent with past practice and is appropriate.

Forecast Debt Cost Rate

YECL forecast a cost of new debt for 2008 of 6.60%. This amount was derived as follows[82]:

Forecast Long Canada Bond Yield	4.55%
Spread	2.00
Issue Costs	0.05
Total	6.60%

YEC submitted in argument that the Canada Long Term Bond yield should be 4.2% based on "current experience" and as supported by the updated forecast for six months to June 30, 2008, of 4.1% that was provided in YEC-YECL-39(g). The Board notes that YEC-YECL-39(g) indicates the 4.1% figure was presented as an actual average yield for the first six months of 2008, and not as an "updated forecast" as YEC indicates.

[81] Application Schedule 8.1
[82] Application, page 8-2, lines 10-14

In reply argument, YEC noted that each Intervenor had raised significant concerns regarding the debt rate. YEC submitted that CW had noted that YECL had ample warning that the forecast Canada bond yields in the 2008 test year would be significantly lower than forecast in November 2007. YEC supported the reductions in debt-rate costs recommended by CW for 2008 and 2009 debt issuances.

In argument, LE submitted that the fact that the actual Canada Long Term Bonds averaged 4.1% in the first half of 2008 and the fact that CU had issued 30-year debentures on August 18 at 5.573% (which would be mirrored down to YECL at 5.623%) indicated that YECL's 2008 forecast for the Canada Long Term Bonds and for the spread were conservative (favored YECL) and called into question the forecast for 2009.

In argument, YECL noted that its actual debt-cost rate for new debt in 2008 was 5.623% but submitted that the forecast included in the Application was based on the best information available at the time and should be accepted by the Board and approved.

In argument, CW submitted that YECL should be directed to use the actual debt cost of 5.623% for 2008, since it is now known. CW disagreed that the forecast debt cost was based on the best information available. CW stated that the 4.55% long Canada forecast was based on a November 2007 forecast employed by the EUB to determine its 2008 generic cost of equity. CW submitted that the fact that the average long Canada yield during the first half of 2008 was 4.1% should have indicated by the date of filing that a downward revision to the debt cost forecast was necessary.

In its argument, CW further submitted that YECL's debt-spread forecast of 200 basis points was apparently based on ATCO Gas' GRA request and was not based on the opinion of CU's staff. CW submitted that CU's actual debt issue cost of 5.623% combined with the "… actual first quarter [2008] long term Canada yield of 4.10% would indicate that the actual premium [spread] for CU's corporate bonds is approximately 150 basis points…[83]" CW submitted that YECL had or should have had ample indication by the time of filing that its forecasted cost of debt was too high. CW indicated: "Given the current financial conditions, Ms. McShane's forecast 2009 long term Canada rate of 4.5% may not be excessive.[84]" However, CW argued that the spread should be reduced to 150 basis points "… based on the premium that CU actually commands in the financial markets.[85]" Based on the 4.5% Canada yield, the 1.50% spread and 0.05% for issue costs, CW submitted that the allowed cost rate for debt issued in 2009 should be 6.05%.

CW added that if the Board did not reduce the costs for the 2008 and 2009 new debt issues as recommended then "… YECL will have embedded in its rates on an on-going basis an extra $35,000 in debt costs that it will not actually incur.[86]"

[83] CW Argument, Section 8
[84] Ibid
[85] Ibid
[86] Ibid

In reply argument, CW reiterated its position that the 6.60% rate was not based on the best information available at the time. CW submitted that there was "… evidence that YECL knew at the time of filing that CU was actually issuing debt at a coupon rate that was well below its forecasted rate in the Application.[87]" CW cited Transcript page 178 where YECL indicated that it had discussions with CU Inc. CW also argued that it was inconsistent of YECL to request that the amount of the issue be adjusted to reflect the actual issue amount but that the issue rate should not be adjusted to actual.

UCG submitted in argument that YECL had not produced evidence that its borrowing via CU Inc. allowed for a better interest rate for YECL and that YECL had admitted that it had not inquired into interest rates from any other financial institution. UCG also noted that the evidence indicated that AE charged a 0.05% fee above the CU opportunity cost. UCG noted that YECL's costs for new loan debentures in 2005 and 2007 has been 5.23% and 5.07% respectively and that interest rates and long term government bonds have had very little variation in 2005, 2006 and 2007. UCG submitted that there was not proper evidence that the 6.6% rate from CU inc. was a fair market value cost as no other institution was approached for the opportunity to compare. UCG submitted that this suggests that the 6.6% rate is inflated and not prudent and should not be passed on to ratepayers.

In reply argument, YECL reiterated that the 6.60% debt rate was based on the "best information available at the time the Application was prepared and, in a forward Test Year approach to regulation, should be accepted by the Board as filed.[88]" YECL submitted that it is clearly the case that the mirroring down of debt costs from YECL's parent is clearly beneficial and are much more favorable than YECL could obtain on its own.

YECL said that the Board, "… must be cognizant of the fact that, while yields are indeed down, there has been an offsetting increase in spreads with the result that utilities would not be able to borrow at low rates"[89]. YECL submitted that the evidence confirms that the requested rate for the test years may be modest, if anything. YECL submitted that its requested cost of debt should be approved as filed.

Views of the Board

The first issue for the Board to determine is whether or not information related to actual debt costs in 2008 that became available after the Application was filed should be considered.

In the Board's view it may consider the best available information that is on the record. Debt costs and its components are observable in the general market and are not entirely specific to any one utility. The Board finds that it can and should consider the updated information available on the record.

[87] CW Reply, page 10
[88] YECL Reply, page 23
[89] YECL Reply, page 24

The Board reviewed the evidence regarding debt costs for 2008 and 2009 based on the information on the record.

Regarding 2008, the Board considers that YECL has confirmed that its debt costs will be 5.623%[90]. The Board is of the view that this is the best available information provided at the hearing on which to base its decision. The Board finds that YECL should use a debt rate of 5.623% for the debt issued in 2008.

Regarding 2009, the Board notes the evidence that actual government yields have declined substantially since the time of the 5.55% forecast that was used by AE. However, the Board notes that forecast debt costs for a future year are seldom exactly equal to prevailing actual debt costs when a forecast is made. The Board notes that no specific evidence regarding market forecasts of 2009 government interest rates was placed on the record or referred to in argument. The Board therefore cannot accept CW's argument that the government bond yield from the first portion of 2008 of 4.1% should be relied on as the forecast for 2009.

The Board also notes YECL's reply argument regarding the fact that increased spreads have offset the lower government yield rates.

The Board does not accept CW's argument supported by YEC that a spread of 150 basis points, based on their view of the indicated actual spread in August 2008, is appropriate. The Board notes that Intervenors did not provide evidence regarding 2009 debt-cost forecasts. Given the credit crisis and the increased spread costs which YECL has referenced, and the lack of alternative evidence regarding a forecast of 2009 interest costs, the Board accepts that YECL's forecast of 6.60% is a reasonable forecast of debt costs for 2009. The Board also notes that CW is not correct in suggesting that if actual borrowing costs turn out to be lower, then YECL will have embedded the higher costs in its rates on an ongoing basis. In fact, this rate would be updated to reflect the actual costs for purpose of future test years beyond 2009.

5.7.1.4 No Cost Capital

YECL included in its Application No Cost Capital amounts of $669,000 and $695,000 for the years 2008 and 2009 respectively. Amounts for deferred pensions including other post-employment benefit plans (OPEB) and the reserve for injuries and damages constituted the no cost capital amounts. Part of the increase for this item related to accounting for the OPEB on the cash basis starting in 2008.

Views of the Board

As there were no issues or concerns raised, the Board accepts the No Cost Capital amounts as filed.

[90] Transcript, page 179, line 25

5.7.2 Rate Base

5.7.2.1 Capital Additions

Page 8-4 of the Application describes at a high level the drivers for capital additions. Capital additions are discussed in Section 5.8 of the Application.

5.7.2.2 Contributions

YECL stated that contributions are received from customers in accordance with the company's investment policy and included contributions of $2,560,000 and $2,506,000 for the test years 2008 and 2009 respectively.

Views of the Board

As there were no issues or concerns raised, the Board accepts the customer contribution amounts as filed.

5.7.2.3 Deferred Charges and Credits

YECL included amounts for Rate Case Reserve, Diesel Plant Major Overhaul Reserve and Fish Lake License Renewal Costs in Deferred Charges and Credits.

Rate Case Reserve

YECL is proposing to use a deferral account to flow through to customers the costs associated with filing its 2008-09 GRA for both the Phase 1 and Phase II applications. YECL has forecast these costs to be $750,000 over the test years. YECL submitted that the arguments of the Intervenors did not comment materially on the Rate Case Reserve account.[91]

In its response to YEC-YECL-45(c), YECL stated:

> At the time of the 1996/97 proceeding Yukon Electrical did have a rate case reserve. In 2005, however, this treatment changed to be consistent with the treatment followed by YEC and supported in Board Order 2005-17.

In addition, YECL in its response to YEC-YECL-45(h) stated:

> To be consistent with the treatment followed by YEC in its 2005-2006 GRA and supported by the Board Order 2005-17, Yukon Electrical adjusted its treatment of rate case costs in 2005 such that it was no longer accorded deferral account treatment for the period 1998-2007.

YECL also testified that by 2005 there was about $450,000 in the Rate Case Reserve and that this reserve was for purposes of rate case issues.[92] YECL explained that the $450,000 reserve amount, "… was put into retained earning as a result of that decision [2005] which, from our perspective, as it related to 1996-97, which was a joint proceeding with joint rate hearing costs, we applied that decision to that."[93]

[91] YECL Reply, page 24
[92] Transcript p. 87
[93] Transcript p. 87

YEC submitted that YECL established a Rate Case Reserve account after the 1996-97 GRA to which it allocated approximately $75,000 each year for rate-case purposes, accumulating $450,000 by 2005.[94] YEC added that YECL, from 1996 to 2005, charged annual expenses of about $75,000 and reported such expenses annually to the Board until 2005. However, in 2005 the $450,000 in the Rate Case Reserve account of YECL was taken into retained earnings of YECL, without review or approval of the Board. YEC submitted that the Board should determine if this YECL Rate Case Reserve was properly put into retained earnings given that at the time it was a rate payer account or whether this amount should be applied to the present Application's rate-case costs.

In its argument, LE submitted that it was disturbing that about $450,000 of rate payers' contributions could be taken directly into retained earnings. LE added that this Reserve Account of ratepayers' money could pay for a large portion of the rest of this GRA for which ratepayers now have to pay again.[95]

UCG submitted that the $30,000 preliminary internal work on this GRA should be paid for by YECL rate case fund "… which Yukon Electrical now conveniently suggest is empty. This is even though Yukon Electrical has not been in front of this Board for some twelve years. If this is indeed the case, the Company should swallow this internal spending as does [sic] other parties in such processes." [96] UCG further contended that the remainder of the $720,000 be adequately broken down and identified.

Views of the Board

The Board finds that the uncontested evidence before the Board is that YECL, at the time of the 1996-97 GRA proceeding, had a deferral account, Rate Case Reserve, which by 2005 had accumulated in it the amount of $450,000. The purpose of this account was to defray the costs of rate applications. In addition, YECL never asked the Board for approval to close this deferral account. The Board is of the view that YECL had to obtain approval to withdraw funds from this account or to close the account and convert the funds to retained earnings.

The Board considered the reasons given by YECL for its action regarding the deferral account, Rate Case Reserve. The Board finds it unreasonable that YECL unilaterally decided that the closing of this account was consistent with the treatment followed by YEC in its 2005-06 GRA. YECL has not provided to the Board any explanation for this position. Also, in the Board's view, Board Order 2005-17 does not support the YECL decision in this matter as this Order related to the YEC 2005 Revenue Requirement and directed YEC to revise the amount in its cost deferral account and to include the allowed hearing costs. Further, as the account was established and by 2005 YECL had not been before the Board with a GRA for a number of years, it would have been reasonable for YECL to assume that YECL would need the funds to defray the costs of a rate case when it filed its next GRA. The Board is supported in its findings by the fact that YECL is now seeking a deferral account, Rate Case Reserve of $750,000 for the test years.

[94] YEC Argument page 46
[95] LE Argument page 9
[96] UCG Argument point 46

As a result, the Board directs YECL to re-establish the Rate Case Reserve Account with the initial balance of $450,000 carried over from 2005 as the beginning balance in 2008 and allow provisions of $150,000 for each of 2008 and 2009 to establish and ending balance in 2009 of $750,000. YECL in its refilling must adjust its revenue requirement accordingly.

Furthermore, the Board directs that YECL must, in future, make an application to this Board to apply any amounts in this account to rate-case proceedings. In general, YECL cannot dispense with any balances in deferral or reserve accounts without prior Board approval.

Regarding Diesel Plant Major Overhaul Reserve and Fish Lake License Renewal Costs in Deferred Charges and Credits, the Board notes that no parties objected to these amounts; therefore, the Board accepts the amounts as filed by YECL except for the Rate Case Reserve, as noted above. The Board directs that YECL is to only use the amounts in these reserve accounts for the purposes for which they are intended. Other uses are not allowed without Board approval.

5.7.2.4 Working Capital

Working Capital amounts of $2,805,000 and $2,650,000 for 2008 and 2009 were included in the Application. No comments were received on working capital.

Views of the Board

The Board finds the working capital amounts and calculations in YECL's application to be reasonable. Therefore, the Board accepts the working capital amounts as filed.

5.8 Capital Additions

Section 9 of YECL's Application lists the capital additions for 2008 and 2009. YECL has forecast capital expenditures of $9,560,000 for 2008 and $13,504,000 for 2009. With the exception for the projects noted below, generally capital additions are for new extensions, distribution improvements, lights, meters, general plant and equipment, and generation.

Generic descriptions of each category and a listing of projects are detailed in pages 9-1 to 9-28 of the Application.

In argument, LE stated: "It is the author's view that the capital expenditures proposed in the Application are higher than is reasonable under the present circumstances[97]…" LE further recommended:

> YECL's approved capital expenditures should be reduced such that their net additions to rate base do not exceed $6.5 million per year (in other words about $9 million per year including contributions in aid of construction).[98]

[97] LE Argument, page 6
[98] Ibid, page 10

YECL in its argument said:

> Yukon Electrical submits that aside from the three projects identified above, that are new to the Test Period, it is "business as usual" for Yukon Electrical from a capital expenditure point of review. Yukon Electrical confirmed that it has available the resources necessary to complete its forecasted capital program (3T397). Yukon Electrical requests that its forecast of capital expenditures be approved as filed.[99]

Views of the Board

The Board shares the concern of LE about the level of capital projects and the ability (resource availability) of YECL to complete all the projects included in the forecast years. The Board notes that YECL's testimony is that it expects to complete the work in their capital plans in the test period.[100]

Therefore, with the exception of the projects noted below, the Board accepts the values for the remaining capital expenditures to be reasonable and consistent with past practice. The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests. Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures.

5.9 Carcross Diesel Power Plant

In its Application, YECL proposed to spend $2.0 million for a new 1.5 MW power plant to be installed at Carcross in 2009. In accordance with the Board-approved Yukon Energy Corporation 20-Year Resource Plan, YECL indicated that communities with loads over 1 MW should have local generation to serve them if the grid should stop serving the community. Of the Intervenors, only LE supported the installation of the power plant noting the frequent outages and the fact that Carcross was the only significant established community in Yukon that did not have back-up diesel generation.

In its argument, UCG submitted that there was no justification for the expenditure, noting that there was no evidence or analysis on the record related to options in lieu of purchasing the diesel unit. YEC agreed with the UCG and explained in its argument that the WAF and MD grid Community Criteria in the 20-Year Resource Plan only suggested that communities over 1.0 MW would be considered as the preferred location for new diesel units, providing grid support as well as local generation during line failures. Further, highlighting this point, YEC pointed out that there was no current need for new diesel units to meet grid system requirements.

[99] YECL Argument, page 33
[100] Transcript Volume 3, October 9, 2008. Page 397, lines 1-6 inclusive

In argument, YECL confirmed that it was concerned with providing safe and reliable service to its customers and indicated that it had introduced Exhibit B-17 to highlight its reliability concerns and the need for backup generation. In its argument, YEC affirmed that there was no written evidence made available prior to the hearing to address local reliability concerns at Carcross and to consider options to address such concerns. YEC further argued that Exhibit B-17, which purported to justify the need for a diesel unit at Carcross by demonstrating statistics for the number of customers affected by outages, was at best misleading. Accordingly, YEC submitted that the Board should not approve the proposed Carcross diesel unit as an addition to YECL's rate base for the test years or any other near-term period.

YECL responded in reply argument that it was of the view that the approval of the Carcross generating station was necessary in order to provide an appropriate level of service to the Carcross-Tagish area. Further, all Yukon customers would benefit from the mobile nature of this standby plant. Accordingly, YECL submitted that the requested capital expenditure should be approved as filed.

Views of the Board

The Board notes LE's support of YECL's proposal to install the 1.5 MW genset in Carcross. However, the Board observes that LE in its argument indicated that YECL had neither examined alternatives nor performed a cost-benefit analysis regarding options to address reliability concerns in the area.

The Board has concerns respecting the lack of evidence on the record that YECL had explored other options with respect to mitigating the reliability in Carcross-Tagish area. The Board notes that tree-related outages have decreased noticeably since the introduction of YECL's new and improved brushing program.[101] Further, in making its finding on this issue, the Board considered proposed distribution improvement programs in the area including line relocates[102] and rebuilds[103] that include pole replacements. The Board finds that YECL has proposed these improvements to address safety and reliability issues in the Carcross-Tagish area. The Board further finds that these types of projects appear to be a reasonable alternative to YECL's proposed Carcross generator to address reliability concerns.

Considering the above, the Board is not convinced that the Carcross generator is the best option at this time to mitigate outages in the Carcross-Tagish area. Therefore, the Board does not approve the proposed Carcross diesel unit in YECL's rate base for the test years. Accordingly, the Board directs YECL in its refiling to reflect the removal of the proposed Carcross diesel unit from its proposed capital additions. Further, at the time of its next GRA, the Board directs YECL to present its business case respecting the Carcross genset if it is still the preferred option to mitigate reliability concerns in the area.

[101] YECL Argument; page 17
[102] Carcross Relocate, Application, page 9-25; Carcross Km 129-131.5, Application, page 9-18
[103] Tagish Road Rebuild, Application, page 9-18; Tagish Section to Taku 2.5 km, Application, page 9-25

In addition, the Board has concerns with YECL's response to YUB-YECL-1. YECL failed to provide recognized indicators that could be used to benchmark distribution reliability in the area and indicated that it tracks reliability on its system as a whole rather than on a line or feeder basis. Recognizing the importance of system reliability, the Board directs YECL in its next GRA to present industry recognized statistics that affirm the success of its projects and program initiatives that have safety and reliability as their basis.

Considering the number of miscellaneous pole-replacement projects YECL has proposed, the Board directs YECL to investigate the replacement of existing poles with taller poles as was suggested by LE and report back to the Board at the time of its next GRA. Further, the Board directs YECL at the time of its next GRA to provide a study that illustrates the initiatives that similar utilities (north of 60) are undertaking to address reliability concerns.

5.10 Haines Junction Diesel Plant

In argument, YECL indicated that it was very clear from the record that the rationale supporting the installation of the Haines Junction unit was as a result of extended outages and lengthy restoration times experienced with respect to this community. YECL submitted that should any residual confusion remain regarding the rationale for the installation of the Haines Junction diesel unit it has now been cleared up, as it had nothing to do with WAF grid capacity.

YEC replied that there was minimal information on the record regarding the need for the unit or any alternatives that were considered. YEC submitted that the Board should require YECL to provide such information prior to approving this unit's inclusion in rate base.

Views of the Board

The Board notes that YECL spent $542,000 on a Haines Junction diesel unit and step-up transformer bank in 1997.[104] The Board notes YECL's argument that the unit was installed to address extended outage and lengthy restoration times. The Board will allow the Haines Junction diesel plant into rate base without prejudice.

5.11 North 60 New Billing System

In its Application, YECL proposed expenditures of $1,008,000 (in 2008) for a new customer care and billing system. No business case was provided with the Application[105].

In argument, UCG noted that the billing system is over 10 years old and makes errors. UCG submitted that "the new billing system costs are not prudent and therefore should not be awarded to capital expenditures[106]."

[104] YEC-YECL-25(a)
[105] The business case was later supplied as Attachment 1 to YUB-YECL 16(b)
[106] UCG Argument, point 37

LE was surprised that a new system would cost more to operate than an existing outdated system and recommended approval of the new billing system providing that YECL gives a detailed O&M cost comparison between the current system and the proposed new system.

YECL argued that the database technology of the existing billing system was no longer economically supportable. YECL further summarized:

> Yukon Electrical confirmed that it is sharing the costs of the new billing system with the other Northwest Territories based ATCO Electric affiliates, in order to minimize costs to all ratepayers (3T337). Yukon Electrical submits that it has conducted an extensive examination to determine the most appropriate billing system for its use and has arrived at a cost effective solution that provides maximum benefits to customers[107].

In reply argument, UCG reaffirmed its argument and requested that the capital costs for this project be denied.

YEC in its reply argument said, "Of all three major capital projects included, the North of 60 Billing Project appears to have the most merit at this time, and Yukon Energy supports LE's recommendation.[108]"

YECL in its reply argument said that other than UCG no party objected to the new billing system. YECL further stated that the old billing system no longer had economies of scale and submitted that it approval should be given for this project.

View of the Board

Most parties appear to generally acknowledge that the old billing system is rapidly becoming obsolete and that past economies of scale for the operations of that system have been lost. The Board is concerned that YECL did not use an independent consultant to evaluate alternatives and make a recommendation. The use of ATCO I-Tek as the evaluator, criteria developer, and ultimately one of the vendors clouds the transparency of this decision.

The Board accepts that a new billing system is required by YECL and, absent other evidence, the evidence on the record supports YECL's choice for its new billing system. Therefore, the Board accepts the costs for a new billing system as filed.

5.12 Automated Meter Reading (AMR)

YECL included within the capital additions $330,000 in 2008 and $3,855,000 in 2009 for AMR installation. The business case for the AMR project was filed as Attachment 1 to YUB-YECL-15(c).

In argument, UCG asked that if the current meters are not broken then why is YECL required to fix them? UCG asked that the AMR costs be denied.

[107] YECL Argument, page 30
[108] YEC Reply, page 43

LE pointed out that some of the benefits listed for the project required further capital outlays. LE added that although it was stated that AMR would reduce meter reading errors, no quantifiable data was presented. According to LE, the AMR system would be more expensive to operate for the first eight years and if there was a 10% cost overrun it would be 15 years before AMR became the cost efficient alternative. LE argued that AMR was a weak project and should be deferred.

YEC argued the position that AMR is not essential, and given the requested increase in controllable costs by YECL, expenditures on AMR are not required. YECL recommended that AMR expenditures not be allowed in rate base for the test years.

CW noted that the AMR project could produce cumulative present value savings of $901,400 over 25 years based on current assumptions and savings of $550,000 and $200,500 over the same period for cost overruns of 10% and 20% respectively. CW shared the same concerns as LE regarding the purported benefits and additional expenditures to achieve those benefits. Concerns about the overstatement of benefits of the AMR project created doubts CW had about the validity of the business case. CW did not oppose approval of the project but was concerned that significant cost overruns could make the project financially unsound. Based on those concerns, CW asked that a cap be placed on the capital expenditures and the level for the cap be placed at 10% above the current estimated cost.

YECL argued that the AMR project is justified based on cost saving over the life of the project. YECL further stated that, "… implementing AMR is a business altering development[109]". The use of AMR by AE and Northwest Territories Power Corporation shows that AMR is a proven technology. YECL concluded that the record shows that AMR gives long and short term benefits to customers and should be approved as filed.

UCG replied that the costs do not warrant the benefits and therefore the cost for the project should be denied.

YEC replied that, "the AMR project is fraught with cost and other risks and lacks any justification as being required or essential for the test years[110]". YEC said it agreed with LE and UCG that the project should not be approved at this time.

In reply, YECL restated its position. YECL said the AMR project is justified solely upon economic benefits over the life of the project. YECL also said it was responsible to bring to the Board projects providing long-term benefits that extend beyond the test years. YECL rejected CW's recommendation that a cap be applied to the project.

Views of the Board

The Board has concerns with the business case for AMR. The business case has an escalation of 3% and yet YECL has asked for a 5% inflation rate over the test years. In the Board's view, several of the benefits in the business case appear overstated. That

[109] YECL Argument, page 30
[110] YEC Reply, page 43

the cross-over of the benefits is nine years away[111] puts the economic benefits of the business case at risk. Due to these concerns, the Board is not prepared to accept this project at this time and directs YECL to remove this project and its costs from rate base. The Board encourages YECL to work with all Intervenors, including YEC, to review and assess the costs and potential benefits of the AMR project. Upon completion of the review, YECL is to submit a new business case that outlines the benefits of such a project over time, how it addresses the concerns raised by Intervenors, and describe potential economies by partnering with YEC and the City of Whitehorse in the scope and implementation of the project. The Board expects this business case to be filed with YECL's next GRA.

5.13 Income Tax

In its Application, YECL made a provision for income taxes of $421,000 for 2008 and $1,060,000 for 2009. Income taxes were calculated using the flow-through method whereby taxable income is minimized by claiming the maximum of all available deductions including capital cost allowances. Future taxes are not booked[112].

YECL has requested a Tax Rate Deferral Account, arguing that income taxes are not under the control of company and not reasonably forecastable; or an error in forecasting could produce a loss or gain of a substantial magnitude[113].

In argument, LE stated that the based on his deduction, YECL is a low-risk utility and the potential deferral amount was small. In reply, LE contended that if income tax rates were going to be reduced, "(A)ny such benefit could have been passed on by including in the Application the anticipated lower tax rate or returning it in another fashion at their discretion (e.g. as no cost capital).[114]"

Views of the Board

The Board accepts the methodology used by YECL for the calculation of income taxes and expects YECL to use this method when it prepares its compliance filing. The Board is not persuaded by YECL's contention that notices of changes in tax rates are not received in sufficient time to be reasonably included in YECL's forecast. Therefore, the Board does not accept YECL's request for an income tax deferral account and directs that YECL not use such an account in its refiling.

The Board directs YECL to refile its 2008-09 revenue requirement to reflect the findings, conclusions and directions in the Reasons within 45 days of the issuance of the Order. Further, the Board directs YECL in its refiling, to provide a summary that sets out a detailed reconciliation of its requested revenue requirement for 2008 and 2009 in its Application to the revenue requirement resulting from the Board's determinations in the Reasons.

[111] The crossover can be even greater if there are cost overruns
[112] Application, page 10-1
[113] Application, page 1-5
[114] LE Reply, page 5

6. OTHER MATTERS

6.1 Independent Power Producers Policy

The Application did not contain any sections with respect to Independent Power Producers (IPPs) or Demand-Side Management (DSM). In Response to YCS-YECL-2, YECL said:

> Yukon Electrical does not have a YUB approved rate for IPP's at the present time. It may be appropriate as a starting point to consider the avoided cost of diesel fuel as one option for pricing of IPP energy. Yukon Electrical is also not aware of any legislation that exists to allow sales of energy to the electrical grid by IPP's. Until the practices and policies are created in the Yukon, Yukon Electrical encourages IPP's to focus on off loading their own power requirements which in turn results in less fuel being burned at the central generation facility.
>
> Yukon Electrical is open to discussions with any IPP who provides a safe, reliable and cost effective solution to offsetting the diesel fuel usage in the communities served by Yukon Electrical.

There were no comments in argument or reply argument on this issue.

Views of the Board

The Board notes the response by YECL to YCS-YECL-10:

> With respect to the establishment of a regulatory and legislative framework, Yukon Electrical believes that this is a critical step that has yet to take place.
>
> Should there be an interest in pursuing this topic further; Yukon electrical would be pleased to discuss it with the YUB, government as well as industry leaders.

The Board sees this as an important long-term issue, critical to security of supply in Yukon and of interest to Yukon ratepayers. Therefore, the Board directs YECL, in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to IPPs to be included as part of YECL's and YEC's next GRA.

6.2 Demand-Side Management (DSM)

The Board shares the concerns of LE submitted in argument; despite the significant fuel costs borne by all ratepayers, there are no DSM programs that reflect conservation and efficiency respecting electricity usage in communities served with isolated diesel plants. LE also noted in the YECL evidence where DSM programs were either strongly endorsed or at the least, did not provide a disincentive to a utility[115].

[115] LE Argument, page 3.

YEC in its reply argument said:

> In this context, it makes sense for the Board to consider how YECL can have an incentive to consider active and effective conservation and efficiency programs in diesel served communities[116].

YECL in its reply argument stated on page 11:

> While Yukon Electrical is always amenable to participating in such programs, its experience is that conservation and efficiency programs are typically lead by a Government based entity, in furtherance of policy objectives and not spear-headed by an individual utility. Notwithstanding, Yukon Electrical remains open to discuss such programs with the Government, YEC and customers.

Views of the Board

The Board views DSM as another critical issue for Yukon. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory.

[116] YEC Reply, page 18.

7. HIGHLIGHTS OF BOARD DIRECTIONS

This section is provided for the convenience of readers and provides highlights of Board Directions. In the event of any difference between the directions in this section and those in the main body of the Board Order and Reasons for Decision, the wording in the main body shall prevail.

1. The Board finds, based on previous years' growth in residential customers, that the number of residential customers will increase by 1.7% in 2009. This 1.7% increase takes into account YECL's projections at the time of filing that there may be a shortage of developed lots in 2009. Accordingly, the Board directs YECL in its refiling to adjust its 2009 forecast with respect to the number of residential customer additions from 1.1% to 1.7%. To be clear, the Board directs YECL in its refiling to increase the number of residential customers to 12,908 from 12,836 currently in the forecast and to reflect this change in related schedules and its revenue requirement in the GRA. (Pages 5-6)
2. The Board directs YECL at the time of its next GRA to include comparisons of its analyses and the analyses undertaken by other utilities in Canada to arrive at sales revenue forecasts. The Board directs YECL at the time of its next GRA to include a detailed study as to what other jurisdictions consider a minimum value for R^2 that is acceptable in regression analyses. The Board directs YECL to undertake a study that compares the types of regression analyses that other utilities may use in order to arrive at their analyses. The Board is of the view that a 2% increase in YECL's residential UPC is reasonable as it appears to be the low end of the variance where actual residential UPCs exceed forecast YECL residential UPCs. Therefore, the Board directs YECL in its refiling to increase its residential UPC by 2%, and to reflect this increase in all related schedules and its revenue requirement for the test years. (Pages 6-7)
3. The Board is not persuaded that the use of a three-year average justifies a decrease in commercial average UPCs for communities outside of Whitehorse. Further, the Board has concerns with the lack of data that forms the basis of the small load commercial customers connected to the system in 2009. The Board has concerns with the difficulties that YECL experienced in obtaining monthly UPC data. Considering the above, the Board finds that the commercial UPC forecast should be increased. The Board directs YECL in its refiling to increase its commercial sales forecast by 2%. To be clear, the Board directs YECL in its refiling to increase its 2008 and 2009 MWh sales per customer to 55.7 and 55.3 respectively. Further, the Board directs YECL in its next GRA to provide a comparative study as to the analyses other utilities make use of to derive sales-revenue forecasts. (Page 8)

4. The Board finds it reasonable to amortize the increased power purchase costs directly related to the Fish Lake rebuild project over time. The Board directs YECL in its refiling to capitalize the forecast purchased power costs associated with the rebuild and to not treat these costs as an expense item in the test years. The Board further directs YECL at the time of its next GRA to provide clear documentation of these incremental power purchases from WAF due to the Fish Lake hydro rebuild. The Board approves YECL's request for continuation of the deferral accounts outlined on Page 11. The Board is concerned with the YECL's proposed Fish Lake hydro generation forecast of 6.2 GW.h for each of the test years, which is a 3.8-GW.h reduction from the 10 GW.h of generation proposed in YECL's last GRA. The Board accepts YEC's suggestion that the available generation at the Fish Lake hydro plant should be based on all years of available data. Accordingly, the Board finds 8.73 GW.h is reasonable as the base generation for the Fish Lake hydro facility, prior to considering the impact of any downtime due to the Fish Lake hydro rebuilds. Therefore, the Board directs YECL in its refilling to reflect base hydro generation of 8.73 GW.h. (Pages 10-11)

5. The Board agrees with YECL that the Pelly Crossing deferral account meets the standard criteria and is reasonable and appropriate. The Board agrees that YECL's proposal to continue a diesel fuel price rider deferral account, in order to address differences between forecast and actual fuel prices, is reasonable and appropriate. Therefore, the Board approves YECL's proposal for a diesel fuel price rider. (Page 12)

6. The Board has concerns respecting YECL's proposal for an average job-class wage increase of 9.5% for 2009 that YECL expects to result from the fall 2008 negotiations, considering the 22.5% increase in average compensation per FTE from 2007 to 2009. The Board is of the view that the proposed increases for the test period are excessive. Further, the Board finds it reasonable to approve average annual compensation increases for the test period of 6.0%. Therefore, the Board directs YECL in its refiling to reflect a compensation increase per FTE of 6.0% for each of the years in the test period. (Page 14)

7. The Board finds a vacancy rate of 3.5, the average actual vacancies for the period 2003 to 2007, to be reasonable for the test years. Therefore, the Board directs YECL in its refiling to reflect a vacancy rate of 3.5 FTEs for each of the test years. (Page 15)

8. The Board does not accept YECL's proposed 5% inflation rate for the two-year test period, as YECL has not shown it is a reasonable inflation rate. Recognizing that YECL purchases a quantum of goods and services outside of the Yukon, the Board does not agree with YEC's recommendation to approve YECL's O&M costs for revenue requirements based solely on a Yukon inflation rate of 2.5%. The Board notes CW's suggestion regarding a hybrid inflation rate comprised of Alberta and Yukon CPI rates. The Board finds it reasonable that the forecast non-labour inflation rate for 2008 and 2009 be 3.75%, which is calculated using a 50/50 weighting and inflation rates of 5.0% (Alberta) and 2.5% (Whitehorse). The Board therefore directs YECL in its refiling to reflect in its revenue requirement, an inflation rate of 3.75% for its O&M costs other than labour. The Board directs

YECL in its next GRA to provide a study that compares what other utilities use as a basis for non-labour inflation rates. (Page 16)

9. The Board finds CW's proposal to accept the I-Tek rates as final for setting information technology and customer care rates appropriate from an efficiency standpoint. Accordingly, the Board approves YECL's proposed affiliate costs subject to the proviso that the inflation rate will be adjusted to the Board-approved inflation rate for non-labour costs. The Board directs YECL in its refiling to align its proposed affiliate costs with the non-labour costs adjusted to reflect the Board-approved non-labour inflation rate. (Page 18)

10. The Board agrees with the position of YEC that the 3.8% increase for 2008 is the most accurate and up-to-date information in this proceeding. Therefore, the Board directs YECL to use 3.8% as the increase in Taxes Other Than Income for 2008 over 2007 actual costs. The Board accepts the 4% forecast increase amount over 2008 costs for 2009 costs as proposed by YECL. (Page 19)

11. With respect to FRSR, the Board is persuaded by the arguments of YEC and CW that consistency in this area is important. Given that the negative net salvage balance continues to grow, the Board does not believe that there is a need to continue to collect such amounts. YECL is to remove these amounts from its depreciation expense for each of the test years and is not to include any amounts for negative net salvage until Board approval is provided. Further, the Board orders that the December 31, 2007, accumulated amount for net negative salvage be shown as a liability and be reduced as salvage costs are incurred for the years commencing with 2008. Similar to YEC, YECL is to inform the Board and interested parties when the balance for this liability account reaches $2 million. (Page 22)

12. The Board cannot accept the equity ratio as proposed by YECL. Given current market conditions which are discussed in the Cost of Debt Section, the Board directs YECL to use the last approved equity ratio of 40%. (Page 27)

13. YECL is directed to use an ROE for 2008 of 9.08%. For 2009, YECL will use a risk premium of 46 basis points above the BCUC 2009 benchmark ROE. (Page 29)

14. The Board finds that YECL should use a debt rate of 5.623% for the debt issued in 2008. (Page 33)

15. As there were no issues or concerns raised, the Board accepts the No Cost Capital amounts as filed. (Page 33)

16. As there were no issues or concerns raised, the Board accepts the customer contribution amounts as filed. (Page 34)

17. The Board directs YECL to re-establish the Rate Case Reserve Account with the initial balance of $450,000 carried over from 2005 as the beginning balance in 2008 and allow provisions of $150,000 for each of 2008 and 2009 to establish and ending balance in 2009 of $750,000. YECL in its refilling must adjust its revenue requirement accordingly. Furthermore, the Board directs that YECL must, in future, make an application to this Board to apply any amounts in this account to rate-case proceedings. In general, YECL cannot dispense with any balances in deferral or reserve accounts without prior Board approval. Regarding Diesel Plant Major

Overhaul Reserve and Fish Lake License Renewal Costs in Deferred Charges and Credits, the Board accepts the amounts as filed by YECL except for the Rate Case Reserve. The Board directs that YECL is to only use the amounts in these reserve accounts for the purposes for which they are intended. Other uses are not allowed without Board approval. (Page 36)

18. The Board finds the working capital amounts and calculations in YECL's application to be reasonable. Therefore, the Board accepts the working capital amounts as filed. (Page 36)

19. With the exception of the projects noted, the Board accepts the values for the remaining capital expenditures to be reasonable and consistent with past practice. The Board directs YECL in future to provide business cases for all major capital expenditures at the time YECL files its rate applications to give the Board and Intervenors better opportunity to examine the business cases and time to allow for written information requests. Further, the Board directs that YECL provide an annual update on its capital plans and expenditures. The Board further directs YECL in future rate applications to provide an itemized list of miscellaneous capital expenditures. (Page 37)

20. The Board finds that YECL has proposed improvements to address safety and reliability issues in the Carcross-Tagish area. The Board further finds that these types of projects appear to be a reasonable alternative to YECL's proposed Carcross generator to address reliability concerns. The Board is not convinced that the Carcross generator is the best option at this time to mitigate outages in the Carcross-Tagish area. Therefore, the Board does not approve the proposed Carcross diesel unit in YECL's rate base for the test years. Accordingly, the Board directs YECL in its refiling to reflect the removal of the proposed Carcross diesel unit from its proposed capital additions. Further, at the time of its next GRA, the Board directs YECL to present its business case respecting the Carcross genset if it is still the preferred option to mitigate reliability concerns in the area. The Board directs YECL in its next GRA to present industry recognized statistics that affirm the success of its projects and program initiatives that have safety and reliability as their basis. The Board directs YECL to investigate the replacement of existing poles with taller poles as was suggested by LE and report back to the Board at the time of its next GRA. Further, the Board directs YECL at the time of its next GRA to provide a study that illustrates the initiatives that similar utilities (north of 60) are undertaking to address reliability concerns. (Page 38)

21. The Board notes that YECL spent $542,000 on a Haines Junction diesel unit and step-up transformer bank in 1997. The Board notes YECL's argument that the unit was installed to address extended outage and lengthy restoration times. The Board will allow the Haines Junction diesel plant into rate base without prejudice (Page 39)

22. The Board accepts that a new billing system is required by YECL and, absent other evidence, the evidence on the record supports YECL's choice for its new billing system. Therefore, the Board accepts the costs for a new billing system as filed. (Page 40)

23. The Board is not prepared to accept the AMR project at this time and directs YECL to remove this project and its costs from rate base. The Board encourages YECL to work with all Intervenors, including YEC, to review and assess the costs and potential benefits of the AMR project. Upon completion of the review, YECL is to submit a new business case that outlines the benefits of such a project over time, how it addresses the concerns raised by Intervenors, and describe potential economies by partnering with YEC and the City of Whitehorse in the scope and implementation of the project. The Board expects this business case to be filed with YECL's next GRA. (Page 42)

24. The Board accepts the methodology used by YECL for the calculation of income taxes and expects YECL to use this method when it prepares its compliance filing. The Board is not persuaded by YECL's contention that notices of changes in tax rates are not received in sufficient time to be reasonably included in YECL's forecast. Therefore, the Board does not accept YECL's request for an income tax deferral account and directs that YECL not use such an account in its refiling. (Page 42)

25. The Board directs YECL to refile its 2008-09 revenue requirement to reflect the findings, conclusions and directions in the Reasons within 45 days of the issuance of the Order. Further, the Board directs YECL in its refiling, to provide a summary that sets out a detailed reconciliation of its requested revenue requirement for 2008 and 2009 in its Application to the revenue requirement resulting from the Board's determinations in the Reasons. (Page 42)

26. The Board directs YECL, in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to IPPs to be included as part of YECL's and YEC's next GRA. (Page 43)

27. The Board directs YECL in conjunction with YEC, to consult with stakeholders and develop a policy paper with respect to DSM initiatives and include this policy paper as part of YECL's and YEC's next GRA. To be clear, YEC and YECL are to jointly lead these processes and jointly submit the policy papers (IPP and DSM) in their next GRA. The DSM policy papers are to provide DSM initiatives developed through negotiations with Intervenors and communities in its service territory and YEC's service territory. (Page 44)

TAB 8

Appendix A to Board order 2015-02

Reasons for Decision

1. Introduction

On October 27, 2014, pursuant to section 62 of the *Public Utilities Act* and section 31 of the Yukon Utilities Board Rules of Practice, Yukon Electrical Company Limited (YECL) filed with the Yukon Utilities Board (Board) an Application for Review and Variance (review application) regarding Board Order 2014-06 and Appendix A, Reasons for Decision, dated April 23, 2014 (Board Order). In its review application, YECL is requesting that the Board vacate its directions in the Board Order to (i) remove all project-related costs of the Watson Lake bi-fuel project from its proposed capital additions to rate base; (ii) reduce the cost of living adjustment (COLA) component of its defined benefit pension expense from 100 to 50 percent of Canadian Consumer Price Index (CPI) up to the three-percent maximum and to adjust its defined benefit pension funding requirement forecast accordingly; and (iii) vary the awarded rate of return on equity of 8.75% and the common equity ratio of 40%.

The grounds for review are as follows:

i. Regarding the Watson Lake bi-fuel project, YECL alleges that fundamental changes in circumstances or facts have occurred since the Board Order; and
ii. In relation to the directions on the COLA adjustment, the rate of return on equity, and the common equity ratio, YECL alleges the Board committed errors of law or jurisdiction, or an error of fact.

In its review application, YECL made submissions on each of these grounds and in support of the relief requested.

The Board uses a two-phase system for applications for review. In the first phase, the review applicant must establish a *prima facie* case sufficient to warrant a review. If it finds that this threshold for review has been met, the Board will hold a new hearing or other proceeding in accordance with its rules of practice to determine the review on its merits and whether the decision should be confirmed, changed or cancelled.

Before making a decision on the first phase of the review application before it, the Board issued a process letter on October 30, 2014, affording interveners an opportunity to submit comments on the first phase of the review application by November 20, 2014 and YECL to reply by December 11, 2014. The Utilities Consumers' Group (UCG) and Yukon Energy Corporation (YEC) submitted comments on the review application. The comments filed by YEC only addressed the rate of return on equity and the common equity ratio. YECL responded to these comments.

In its submission, UCG questioned the existence of fundamental changes in circumstances or facts alleged by YECL in relation to the Watson Lake bi-fuel project and disputed that such changes or facts occurred. UCG pointed to the record and the Board Order to address the issues raised in the review application. It concluded that YECL did not make a *prima facie* case that the Board made errors of law or jurisdiction, or an error of fact in the Board Order for the reasons set out in its submission.

YEC submitted that YECL did not establish a *prima facie* case that the Board erred in denying YECL a risk premium or an increase in its common equity ratio because the Board Order is consistent with prior Board rulings to select and implement a generic cost-of-capital model in accordance with principles established in Canada for utilities, based on the evidence then provided to the Board during each proceeding. In support of its submissions, YEC pointed to the record of the YECL proceeding in question, the statements of the Board in the Board Order regarding the risk premium and the common equity ratio and Board Order 2009-02, as well as Board Order 2013-1.

YECL replied to UCG's comments. It argued that the UCG was incorrect in its submissions for the reasons stated in its reply. YECL also took issue with the submissions of YEC. It reiterated its request that the Board convene a phase two review on the merits. It asked that, in the alternative, the Board could vacate the directions in questions and vary the rate of return on equity and the common equity ratio.

2. Test for review and variance

Section 62 of the *Public Utilities Act* (Act) states:

> **62** The board may review, change, or cancel any decision or order made by it, and may re-hear any application or complaint before deciding it.

The Board has enacted rules of practice under section 10 of the Act which include the following provisions regarding applications for review:

> 31. (1) Pursuant to section 62 of the *Act*, the Board will consider the following as grounds for review:
>
> a) the Board has made an error in jurisdiction;
> b) the Board has made an error in fact or law;
> c) there has been a fundamental change in circumstances or facts since the decision or order;
> d) a basic principle has not been raised in the original proceedings;
> e) a new principle has arisen as a result of the decision nor order;
> f) such other grounds as the Board may determine require a review.
>
> (2) The application for review should as a minimum set forth the following:
>
> a) the grounds upon which the application is based;
> b) a brief statement of facts supporting the alleged ground(s) for review;
> c) if new evidence is sought to be filed, a statement of the nature and purpose of the evidence;

d) any further matter that the applicant believes will assist the Board in reaching a decision to grant a review.

(3) The Board will use a two-phase system for applications for review. Such a process enables certain applications to be dealt with expeditiously and economically. An application for review will be subject to an initial screening phase where the applicant must establish a prima facie case sufficient to warrant full consideration by the Board. In the first phase, the Board will assess an application having regard to some or all of the following questions:

a) Should there be a review by the Board?
b) If there is to be a review, should the Board hear new evidence and should the parties be given the opportunity to present evidence?
c) If there is to be review, should it focus on the items from the application for review, a subset of those items or additional items?

(4) Upon receipt of an application for review, the Board will invite registered parties to comment on the application for review regarding the questions set out in subsection (3) for the first phase of the review and the applicant for review may respond to the comments received.

(5) In the case of an alleged error, in order to advance to the second phase of the process, the application must show that:
a) the claim of error is substantiated on a prima facie basis; and
b) the error has significant material implications.

(6) If there is a second phase, then the Board will hear full arguments on the merits of the application.

In arriving at this decision on the screening phase of the review application, the Board has considered all arguments and submissions made by YECL and the comments of the UCG and YEC. The Board Order, the record of the proceeding including evidence at the hearing which resulted in the Board Order were also considered for this decision. References in this decision to specific arguments and submissions of YECL and comments of UCG and YEC, or specific parts of the Board Order or the record of the proceeding, are intended to assist the reader in understanding the Board's reasoning relating to a particular matter and should not be taken as an indication that it did not consider all relevant portions of the arguments, submissions, comments, Board Order or record with respect to any matter.

3. Discussion of the Board Order and grounds for review

The Board has divided its decision on the screening phase of the review application into two parts based on the grounds for review. First, the Board discusses the Watson Lake bi-fuel project to determine whether YECL has made a *prima facie* case that there has been a fundamental change in circumstances or facts since the Board Order was made.

Second, the Board discusses the COLA adjustment, the rate of return on equity, and the common equity ratio to determine whether YECL has made a *prima facie* case that the Board made an error in fact or errors law or jurisdiction.

i. Watson Lake bi-fuel project

The fundamental change in circumstances or facts alleged by YECL is that the liquid natural gas (LNG) market has developed sufficiently to enable the validation of the Watson Lake bi-fuel project lease costs using competitive tendering to show that these costs are at fair market value. Also, YECL stated that the Board's recommended approval of the YEC Whitehorse Diesel Project to Natural Gas Conversion Project enables a more conclusive understanding of how the benefits of its project will be assessed and determined.[1]

The reasons of the Board for rejecting YECL's proposal to include the Watson Lake bi-fuel project in its rate base are as follows:

> The Board considers of note YECL's submission that "this is a first-of-its-kind project, a pilot project that we're doing in a phased approach to prove on one unit at Watson Lake over a one-year period." The Board also has taken into account YECL's response that this "is a first-of-its-kind project, to be proven through demonstration on a single unit before proceeding to conversion of the remaining units while ensuring that a reliable supply of natural gas is available and the performance of the entire facility is acceptable."
>
> **…**
>
> The Board takes note of YECL's submission that when comparing the project capital costs to the cumulative fuel savings, a simple project payback of nine years was shown. However, in the same intervener request, YECL pointed out that a competitive market for LNG supply did not yet exist as there was only one Western Canadian supplier of LNG at the time, albeit two other suppliers were expected to be in the market in 2014.
>
> The Board has taken into account the lack of a competitive tendering process as evidenced by YECL's submission that a "competing lease provider was not in the market at the time to meet the needs of the Watson Lake project in 2012." However, YECL submitted that YECL had full visibility into the:
>
> > …competitive process for the storage vapourization equipment… and are working with ATCO Gas under the conditions of a fair market value arrangement then with what we'll provide with respect to the pricing components that are

[1] YECL review application page 4

> within that various components for the equipment and for the services that are being provided and for a return on the project.
>
> In the Board's view, fair market value is best determined through a competitive tender process. In this case, the lack of such a process leads the Board to question the costs of the proposed project. The Board considers that the markup in determining the lease price appears high. (footnotes omitted)[2]

The Board was aware that a market was starting to be established for the supply of LNG and that the evaluation of the LNG facility was an emerging market and the reasons for YECL proposing a lease for equipment and services.[3] The Board took into account the YECL submission that in 2012 there was no competing lease provider in the market to meet the needs of the Watson Lake bi-fuel project in 2012.

The Board Order was made on the evidence before it which included the hearing held in November 2013. During the hearing, the issue of the potential changes in the LNG market for the supply of LNG and LNG facilities was canvassed at length and is addressed in the Board's reasons. In its reasons, the Board stated its view that fair market value is best determined through a competitive tender process rather than as argued by YECL that its lease agreement with ATCO Gas was a fair market value arrangement. The Board questioned the costs of the proposed project because of the lack of a competitive process and considered that the markup in determining the lease price appeared high. Also, in part, the Board rejected the project because it was the first of its kind and was going to be tested as a pilot project. Contrary to YEC's submissions in its review application, the Board did not take issue with YECL's submissions that when comparing the project capital costs to the cumulative fuel savings, a simple project payback of nine years was shown.

The Board is of the view that the fundamental change in circumstances or facts must be construed narrowly to preserve the integrity of the decision which was based on the business case presented to the Board. The Board considers that a review on the grounds of a fundamental change in circumstances or facts cannot be used to subsequently bolster a business case for the Watson Lake bi-fuel project that the Board rejected for a number of reasons. During the course of the proceeding, the Board was aware of the potential changes in the LNG market for the supply of LNG and for LNG facilities. Given that the Board was aware of potential changes in the LNG market, the Board is not persuaded that there is a fundamental change in circumstances or facts on which to base the consideration of new evidence which was prepared by YECL a number of months after the Board Order was rendered in this case.

[2] Appendix A, Reasons for Decision, pages 81 and 82
[3] Transcript, Volume 1, November 4, 2013 page 87 and 88

Also, the Board does not accept the submissions of YECL that subsequent considerations of the Board of the economic benefits of the YEC Whitehorse Diesel to Natural Gas Conversion Project warrant a reconsideration of the Watson Lake bi-fuel project. In its reasons, as noted above, the Board did not reject the Watson Lake bi-fuel project based on the economic benefits of the project. It did not take issue with YECL's submission that when comparing the project capital costs to the cumulative fuel savings, a simple project payback of nine years was shown.

Further, the Board does not consider the two projects are comparable and YECL cannot attempt to present additional evidence based on subsequent assumptions accepted by the Board in a different case.

For these reasons, the Board considers that YECL has not made a *prima facie* case to warrant a review on the basis of a fundamental change in circumstances or facts in relation to the Watson Lake bi-fuel project.

ii. Errors in fact and errors of law or in jurisdiction

a. COLA adjustment

YECL alleged that the Board failed to consider the prudency of the COLA costs and the presumption of prudence, failed to assess the prudence of COLA costs independently of potential impact on ratepayers, and overlooked the new pension evidence. The Board does not accept YECL's arguments that the Board failed to consider the prudency of the COLA costs and that a presumption of prudence exists in relation to these costs for the following reasons.

First, in this case, YECL mainly argued that these costs were reasonable and appropriate and that the historical practice of including the COLA adjustment costs should be continued.

Second, the presumption of prudence, as argued in the review application by YECL, did not apply in this case because there was material put on the record at the hearing adduced by way of cross-examination which did not support the position taken by YECL and YECL gave testimony at the hearing in relation to its pension plans and that these were the same pension plans that were considered by the Alberta Utilities Commission in Decision 2010-189 and Decision 2011-391. The applicability of these decisions is further supported by the submissions of YECL in its review application.

Third, in Undertaking No. 3 filed subsequent to the oral hearing, YECL filed additional information which the Board considered. In its review application, YECL referred to this information as the new pension evidence. This information was filed prior to argument and reply; therefore, the opportunity to test this information was not available. This new pension information was the Mercer report dated November 4, 2013, on the total remuneration review of ATCO Utilities, which YECL contended supported the reasonableness of its request for 100 percent of the COLA adjustment. Further, as noted in the Board Order, the evidence and the submissions of YECL in argument and

reply addressed this issue and the review application reiterates YECL's arguments on the new pension information in the proceeding.

Fourth, in making its finding to reduce the COLA adjustment, the Board relied on evidence on the record, and argument and reply of the parties. The COLA adjustment costs are forecast costs for the test years in question and these forecast costs did not engage a prudence test. The Board was considering the reasonableness of the forecast costs and YECL had the onus to show that the costs were reasonable. In making its direction to reduce the COLA adjustment, the Board was not satisfied that YECL had demonstrated that the COLA adjustments forecast costs were reasonable and required for the provision of utility service.

As a result, the Board finds that YECL has not substantiated its claim of errors on a *prima facie* basis.

b. Rate of return and common equity ratio

YECL alleged that the Board failed to set a fair return on rate base for YECL, used the wrong test in determining the return on rate base and overlooked or disregarded YECL's extensive evidence regarding its business risk, failed to apply the stand-alone principle in setting YECL's capital structure, and unfairly deviated from its recent prior capital structure rulings. In its consideration of these allegations, the Board reviewed the Board Order in relation to the setting of the rate of return and the record of the proceeding. In the Board Order, the Board stated:

> In Board Order 2009-02, the Board made its views known regarding generic cost-of-capital models. The Board set out three questions that need to be answered in relation to applicable generic cost-of-capital models and risk premiums:
>
> (1) Which generic cost-of-capital model should be used and from which jurisdiction?
> (2) Should a risk premium be applied?
> (3) What risk premium should be applied to YECL? [4]

In response to the first question, the Board stated that the parties agreed that the British Columbia Utilities Commission (BCUC) generic cost-of-capital benchmark of 8.75% should be used and that this was in keeping with the Board's precedent and practice. The Board added that this benchmark is only used to determine return on equity but not equity thickness. The Board continued by stating that:

> [a]t the time of Board Order 2009-02, the BCUC benchmark utility was FortisBC. For the most recent BCUC decision, the benchmark utility is Fortis Energy.

[4] Appendix A Reasons for Decision pages 49 and 50

> Regarding the question on the application of a risk premium, in Board Order 2009-02, the benchmark utility was FortisBC and evidence had previously been submitted regarding the comparability of the BCUC benchmark utility to YEC. Appendix A, Reasons for Decision, attached to Board Order 2005-12…
>
> …
>
> **Determination** [Appendix A to Board order 2005-12]
> The Board is of the opinion that the rate of return on common equity that YEC is requesting is reasonable, given their level of risk in relation to other utilities within their peer group. Using the BCUC automated adjustment mechanism as a proxy of rate of return on equity does not impose a precedent in the Yukon, and is an expedient and means of determining return for the current one year period. As for the issue of risk premium, the Board agrees that YEC likely falls somewhere between PNG at 65 basis points, and FortisBC at 40 basis points. To ensure that there is sufficient forecast risk within the revenue requirement model, YEC should be at risk for their forecasts of load, OM&A and capital expenditures. (Page 45)

However, the Board considered that YECL had not provided an assessment within the proceeding in question regarding the comparability of YECL to the BCUC benchmark utility, Fortis Energy. It stated:

> BCUC Order G-75-13 — the Stage 1 GCOC proceeding decision dated May 10, 2013 — identifies Fortis Energy as a gas distribution utility. Other than it being a distribution and regulated utility, no other comparisons to YECL can be gleaned from the benchmark decision. As a result, the determination of whether a risk premium should be applied is not clear.
>
> The Board finds that YECL has not established a prima facie case to quantify a risk premium over the BCUC benchmark utility. Therefore, the Board directs YECL, in its compliance filing to use an ROE of 8.75 percent, an ROE equal to that for the BCUC GCOC benchmark utility. YECL is also directed to provide justification for a risk premium relative to the BCUC GCOC standard in its next GRA.[5]

Based on its review of the Board Order and the record of the proceeding, the Board is of the view that YECL has not substantiated a *prima facie* case of error regarding the setting of its rate of return for the test period. The Board Order on the rate of return is consistent with prior Board decisions to select and implement a generic cost-of-capital model in accordance with principles established in Canada for utilities, based on the evidence provided to the Board during each proceeding. As stated above, the Board has set out the questions that the Board must address in selecting in any specific proceeding an applicable cost-of-capital model and risk premiums. After selecting a

[5] Appendix A, reasons for Decision page 51

specific generic cost-of-capital model in a specific proceeding, the Board does not consider modifications from other jurisdictions that are not consistent with the selected model. The Board was consistent with the analysis set out in its reasons to Board Order 2005-12 to consider whether there was evidence comparing YECL to the peer group considered by BCUC. There was no evidence before the Board in the YECL proceeding on updated risk premiums for the BCUC generic cost-of-capital model. YUB-YECL-33(b) confirms that the Board during this proceeding had no evidence on an approved rate of return for FortisBC Inc., FortisBC Energy (Vancouver Island), FortisBC Energy (Whistler), Pacific Northern Gas Ltd. or Pacific Northern Gas (N.E.) Ltd., the likely comparator group for determining a risk premium. Also, YECL did not show that its risks had changed to warrant a risk premium.

Regarding the common equity ratio, the Board stated:

> The direction given regarding the stand-alone principle in Appendix A to Board Order 2009-02 speaks for itself. The Board has not been persuaded in this proceeding to alter that position.
>
> In terms of equity thickness, this Board has not relied upon the results of generic proceedings from other jurisdictions. Although past references have been acknowledged regarding other North of 60 utilities, the Board has used utilities within Yukon in its decision-making. In this proceeding, YECL has stated that its business risks are somewhat less than those of YEC. YECL has also stated that its business risks for this application are largely consistent with those assessed in its 2008-09 Application.
>
> The Board accepts the position of YEC that if YEC's business risks are higher than those of YECL, then it would not make sense to approve an equity ratio for YECL higher than that approved for YEC.
>
> Further, although YECL has provided examples of jurisdictions where higher equity thicknesses have been granted the benchmark utility in the BCUC GCOC proceeding was awarded an equity thickness of 38.5 percent. The Board considers that the equity thickness presented for the NWT jurisdiction or for the BCUC GCOC benchmark utility is not comparable to YECL. Therefore, the Board allows YECL to continue to have an equity thickness that is equal to that awarded to YEC — that is, 40 percent — and directs YECL to reflect such in its compliance filing. Further, as YECL has stated that its business risks are consistent with those in its 2008-09 GRA application, the Board is satisfied that maintaining the same equity thickness it has allowed in YECL's 2008-09 GRA is fair and reasonable.[6]

[6] Appendix A, Reasons for decision, page 54

Based on the above findings, the Board considers it has consistently applied recent previous determinations on capital structure including the determination in Board Order 2009-02 that the stand-alone principle did not apply to YECL. Even though it was not persuaded by the submissions of YECL on the stand-alone principle in this proceeding, the Board awarded the same common equity ratio that it had awarded to YECL in Board Order 2009-02 and to YEC in Board Order 2013-01, although YEC's business risks are higher than those of YECL and YEC is a stand-alone utility. Accordingly, YECL has not substantiated a *prima facie* case that the Board erred in setting YECL's common equity ratio.

Conclusion

Based on the above, the Board did not need to consider the materiality threshold and dismisses YECL's review application.

TAB 9

Northwestern Utilities Limited and The Public Utilities Board of the Province of Alberta *Appellants*;

and

The City of Edmonton *Respondent*.

1977: November 28; 1978: October 3.

Present: Laskin C.J. and Ritchie, Spence, Pigeon, Dickson, Estey and Pratte JJ.

ON APPEAL FROM THE SUPREME COURT OF ALBERTA, APPELLATE DIVISION

Public utilities — Application for interim rate increase — Order of Public Utilities Board permitting recovery of losses incurred before date of application — Board thereby offending provisions of s. 31 of The Gas Utilities Act, R.S.A. 1970, c. 158 — Application of s. 8 of The Administrative Procedures Act, R.S.A. 1970, c. 2, to proceedings — Matter returned to Board for continuation of hearing.

Commencing on August 20, 1974, the appellant company filed an application with the Alberta Public Utilities Board for an order determining the rate base and fixing a fair return thereon and approving the rates and charges for the natural gas supplied by the company to its customers. The application made reference to the powers under s. 31 of *The Gas Utilities Act*, R.S.A. 1970, c. 158, by asking for an order "giving effect to such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". Finally the application sought an order fixing interim rates pending the establishment of "final rates". As a result of this application several interim orders were issued between November 15, 1974, and June 30, 1975. In response to the application of August 20, 1974, the Board by order made on September 15, 1975, established the rate base, a fair return thereon and the total utility requirement at $72,141,000. These items were respectively found and included in the order on the basis of "actual 1974" figures and "forecast 1975" figures. The Board then directed the company to file a schedule of rates "designed to generate the foregoing total utility revenue requirements approved by the Board".

On August 20, 1975, the company filed with the Board an application for an order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by [the company] to its customers"; and on September 25, 1975, it filed an application for an interim order "approving changes in existing rates, tolls

Northwestern Utilities Limited et The Public Utilities Board de la Province de l'Alberta *Appelantes*;

et

La ville d'Edmonton *Intimée*.

1977: 28 novembre; 1978: 3 octobre.

Présents: Le juge en chef Laskin et les juges Ritchie, Spence, Pigeon, Dickson, Estey et Pratte.

EN APPEL DE LA DIVISION D'APPEL DE LA COUR SUPRÊME DE L'ALBERTA

Services publics — Requête visant une augmentation provisoire de tarifs — Ordonnance de The Public Utilities Board permettant le recouvrement de pertes subies avant la date de la requête — La Commission n'a pas respecté l'art. 31 de The Gas Utilities Act, R.S.A. 1970, chap. 158 — Application aux procédures de l'art. 8 de The Administrative Procedures Act, R.S.A. 1970, chap. 2 — Affaire renvoyée à la Commission pour qu'elle en poursuive l'audition.

Le 20 août 1974, la compagnie appelante a demandé à The Public Utilities Board de l'Alberta une ordonnance établissant une base de tarification et un rendement convenable et approuvant les tarifs et droits qu'elle voulait imposer à ses clients pour le gaz naturel qu'elle distribuait. Se référant aux pouvoirs prévus à l'art. 31 de *The Gas Utilities Act*, R.S.A. 1970, chap. 158, elle demandait une ordonnance «tenant compte de la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande». En outre, elle demandait une ordonnance établissant des tarifs provisoires jusqu'à la fixation des «tarifs définitifs». En conséquence, plusieurs ordonnances provisoires ont été rendues entre le 15 novembre 1974 et le 30 juin 1975. En réponse à la requête du 20 août 1974, la Commission rendait, le 15 septembre 1975, une ordonnance qui établissait une base de tarification et un rendement convenable et fixait le revenu total nécessaire à l'entreprise à $72,141,000. Ces montants inclus dans l'ordonnance étaient calculés en fonction des «données réelles pour 1974» et des «prévisions pour 1975». La Commission a ensuite ordonné à la compagnie de produire un tarif «apte à produire le revenu total nécessaire à l'entreprise approuvé par la Commission».

Le 20 août 1975, la compagnie a présenté à la Commission une requête en vue d'obtenir une ordonnance «approuvant les modifications aux tarifs, taxes et droits actuellement perçus par [la compagnie] pour le gaz distribué et les services fournis à ses clients»; cette requête fut suivie d'une autre, datée du 25 septembre

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or charges for gas supplied and services rendered by [the company] to its customers pending final determination of the matter". The application of 1975 recited the history of the 1974 application and stated that the operating costs and gas costs of the company "have increased substantially over the amounts included in the 1974 application and continue to increase". After reciting that the Board in response to the 1974 application has awarded the applicant "interim refundable rates", the 1975 application went on to state that the "existing rates charged by the applicant for natural gas do not produce revenues sufficient to provide for its present or prospective proper operating and depreciation expense and a fair return on the property used in the service to the public". Therefore the company went on to apply for an order determining the rate base, and a fair return thereon, and fixing and approving rates for natural gas supplied by the company to its customers. The company sought as well an order giving effect to "such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". The 1975 application sought as well interim rates "pending the fixing of final rates".

1975, pour obtenir une ordonnance provisoire «approuvant, jusqu'à ce qu'une décision définitive soit rendue, les modifications aux tarifs, taxes et droits actuellement perçus par [la compagnie] pour le gaz distribué et les services fournis à ses clients». La requête de 1975 fait l'historique de la requête de 1974 et souligne que les frais d'exploitation de la compagnie et le coût du gaz «ont considérablement augmenté comparativement aux montants indiqués dans la requête de 1974 et continuent d'augmenter». Après avoir mentionné qu'à la suite de la requête présentée en 1974, la Commission avait accordé à la requérante des «tarifs provisoires remboursables», la requête de 1975 allègue que «les tarifs actuellement perçus par la requérante pour son gaz naturel ne produisent pas un revenu suffisant pour lui permettre de faire face à ses dépenses actuelles et futures d'exploitation et d'amortissement et d'obtenir un taux de rendement convenable sur l'investissement utilisé au service du public». La compagnie a alors demandé une ordonnance qui établisse une base de tarification et un rendement convenable, et fixe et approuve les tarifs à percevoir par la compagnie pour la distribution de gaz naturel. La compagnie a également demandé une ordonnance tenant compte de «la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande». La requête de 1975 demandait en outre une ordonnance fixant des tarifs provisoires applicables «jusqu'à l'établissement de tarifs définitifs».

By its order of October 1, 1975, the Board granted an interim increase in rates the effect of which was to allow the company to receive $2,785,000 in excess of its revenues for 1975 which would have been received under the then existing rates. The City of Edmonton appealed from this interim order to the Appellate Division of the Supreme Court of Alberta pursuant to s. 62 of *The Public Utilities Board Act*, R.S.A. 1970, c. 302. The majority of the Appellate Division set aside the order and remitted it to the Board for reconsideration on two grounds: (1) that the effect of the order was a contravention of s. 31 of *The Gas Utilities Act* in that the company was thereby granted recovery of losses incurred before the date of application, namely, August 20, 1975; and (2) that the Board failed to comply with s. 8 of *The Administrative Procedures Act*, R.S.A. 1970, c. 2, by reason of its failure to give reasons for its decision. The company and the Board appealed to this Court from the decision of the Appellate Division.

Dans son ordonnance du 1er octobre 1975, la Commission a accordé une augmentation provisoire de tarifs permettant à la compagnie de percevoir un revenu supérieur de $2,785,000 à celui qu'elle aurait normalement perçu en 1975. La ville d'Edmonton a interjeté appel de cette ordonnance provisoire devant la Division d'appel de la Cour suprême de l'Alberta en vertu de l'art. 62 de *The Public Utilities Board Act*, R.S.A. 1970, chap. 302. Par un jugement rendu à la majorité, la Division d'appel a infirmé l'ordonnance et a renvoyé l'affaire devant la Commission pour un nouvel examen en se fondant sur deux motifs: (1) l'ordonnance produit un résultat qui contrevient à l'art. 31 de *The Gas Utilities Act*, car elle permet à la compagnie de recouvrer des pertes subies avant la présentation de la requête, c.-à-d. le 20 août 1975; et (2) la Commission n'a pas respecté l'art. 8 de *The Administrative Procedures Act*, R.S.A. 1970, chap. 2, en ne consignant pas les motifs de sa décision. La compagnie et la Commission ont interjeté appel devant cette Cour de cette décision de la Division d'appel.

Held: The appeal should be dismissed and the matter returned to The Public Utilities Board for continuation of the hearing of the company's application of August 20, 1975.

Arrêt: Le pourvoi doit être rejeté et l'affaire doit être renvoyée à The Public Utilities Board pour qu'elle poursuive l'audition de la requête de la compagnie présentée le 20 août 1975.

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The word "losses" as it is employed in s. 31 does not refer to accounting losses in the sense of a net loss occurring in a defined fiscal period but rather refers to the loss of revenue suffered by a utility during a defined period by reason of the delay in the imposition during that period of the proposed increased rates.

The first of the two principal issues in this appeal, *i.e.*, whether the Board by its interim order of October 1, 1975, offended the provisions of s. 31 by granting as alleged by the City an order permitting the recovery of losses incurred before the date of the application, August 20, 1975, was very narrow. The issue was simply whether or not the company by not applying in the 1974 application for a further interim order caused the Board to respond to the new application in 1975 in such a way as to authorize a new tariff which when implemented by the company will have the effect of recovering from future gas consumers revenue losses incurred by the company with respect to gas deliveries made to consumers prior to the date of the application in question (August 20, 1975) or prior to the advent of the October 1, 1975, rates in a manner not authorized by s. 31.

The majority in the Court below observed that "*prima facie* the new tentative rate base includes an amount for revenue losses in 1975 up to the date of the application in August, since the figures do not purport to apportion the loss between the two periods of the year". This Court was not prepared to say that a *prima facie* case had been established that the effect of the application of the interim rates from October 1, 1975, onwards will be the recovery in the future of revenue shortfalls incurred prior to August 20, 1975. The test was not whether the "new tentative rate base includes an amount for revenue losses" but rather the question was whether or not the interim rates prospectively applied will produce an amount in excess of the estimated total revenue requirements for the same period of the utility by reason of the inclusion in the computation of those future requirements of revenue shortfalls which have occurred prior to the date of the application in question, whether or not those "shortfalls" have been somehow incorporated into the rate base or have been included in the operating expenses forecast for the period in which the new interim rates will be applied, subject always to the Board's limited power under s. 31.

The company submitted that a determination of what is or is not a 'past loss' is a pure question of fact and as such is not subject to appeal by reason of s. 62 of *The Public Utilities Board Act*, which limits appeals from Board decisions to questions of "law or jurisdiction". The appeal before this Court involved a determination

Le mot «pertes» à l'art. 31 ne renvoie pas aux pertes comptables au sens d'une perte nette subie au cours d'une année d'imposition, mais plutôt à la perte de revenu subie par l'entreprise au cours d'une période précise en raison du retard à mettre en vigueur, durant cette période, les augmentations projetées.

La première des deux principales questions en litige dans ce pourvoi qui consiste à déterminer si l'ordonnance provisoire rendue par la Commission le 1er octobre 1975 contrevient à l'art. 31 en permettant, selon la Ville, le recouvrement de pertes subies avant la présentation de la requête, le 20 août 1975, est très limitée. Il s'agit uniquement de déterminer si, en ne demandant pas d'ordonnance provisoire supplémentaire dans sa requête de 1974, la compagnie a amené la Commission à répondre à la nouvelle requête de 1975 de manière à autoriser des tarifs qui auraient pour effet de faire supporter par les nouveaux consommateurs de gaz les pertes de revenu sur le gaz livré avant la date de la requête (soit le 20 août 1975) ou avant la mise en vigueur des tarifs du 1er octobre 1975, mais d'une façon qui n'est pas autorisée par l'art. 31.

La Cour d'appel, à la majorité, a fait remarquer que «*prima facie* la nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu subies depuis le début de 1975 jusqu'à la date de la présentation de la requête, en août, car les calculs ne répartissent pas la perte entre les deux périodes de l'année». Cette Cour n'est pas prête à dire qu'il est établi *prima facie* que l'imposition des tarifs provisoires à compter du 1er octobre 1975 permettait le recouvrement dans l'avenir de pertes de revenu subies avant le 20 août 1975. Au lieu de se demander si la «nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu», il faut se demander si l'imposition dans l'avenir des tarifs provisoires procurera un revenu excédant le revenu total requis selon les calculs pour la même période, suite à l'inclusion dans le calcul d'un montant destiné à couvrir les manques à gagner subis avant la date de la présentation de la requête, que ces derniers aient ou non été inclus, de quelque façon que ce soit, dans la base de tarification ou aient été inclus dans les dépenses d'exploitation prévues pour la période durant laquelle les nouveaux tarifs provisoires seront imposés, sous réserve évidemment du pouvoir limité de la Commission en vertu de l'art. 31.

La compagnie a plaidé que la détermination de ce qui constitue une «perte passée» est une question de fait, non susceptible d'appel en vertu de l'art. 62 de *The Public Utilities Board Act*; cet article limite l'appel des décisions de la Commission aux seules questions de «droit ou de compétence». Le présent pourvoi implique l'analyse

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of the intent of the Legislature with respect to the Board's jurisdiction to take into account shortfalls in revenue or excess expenditures occurring or properly allocable to a period of time prior to an application for the establishment of rates under the Act. The Board's decision as to characterization of "the forecast revenue deficiency in the 1975 future test year" of the company involved a determination of the matters of which cognizance may be taken by the Board in setting rates under the statute. This is a question of law and may properly be made the subject of an appeal to a court pursuant to s. 62. The disposition of an application which involved the Board in construing ss. 28 and 31 of *The Gas Utilities Act* raises a question of law and may well go to the jurisdiction of the Board.

However, it was not possible for the reviewing tribunal in the circumstances in this proceeding to ascertain from the Board's order whether the Board acted within or outside the ambit of its statutory authority. The form and content of the Board's order were so narrow in scope and of such extraordinary brevity that one was left without guidance as to the basis upon which the rates had been established for the period October 1, 1975, onwards. Hence this submission of the company failed.

As to the second issue, namely the application to these proceedings of s. 8 of *The Administrative Procedures Act*, which provision imposes upon certain administrative tribunals the obligation of providing the parties to its proceedings with a written statement of its decision and the facts upon which the decision is based and the reasons for it, the Board in its decision allowing the interim rate increase failed to meet the requirements of this section. The failure of the Board to perform its function under s. 8 included most seriously a failure to set out "the findings of fact upon which it based its decision" so that the parties and a reviewing tribunal were unable to determine whether or not in discharging its functions, the Board had remained within or had transgressed the boundaries of its jurisdiction established by its parent statute. The appellants were not assisted by the decision in *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.* (1976), 2 A.R. 453, aff'd [1977] 2 S.C.R. 822, to the effect that under s. 8 of *The Administrative Procedures Act* the reasons must be proper, adequate and intelligible, and must enable the person concerned to assess whether he has grounds of appeal. Nor could the Board rely on the peculiar nature of the order in this case, being an interim order with the amounts payable thereunder perhaps being refundable at some later date, to deny the obligation to give reasons. The order of the

de l'intention du législateur relativement au pouvoir de la Commission de tenir compte des manques à gagner ou des dépenses excédentaires engagées avant la présentation d'une demande de nouveaux tarifs en vertu de la Loi. La décision de la Commission au sujet du «manque à gagner prévu pour 1975, l'année témoin», comporte la détermination de questions dont la Commission prend connaissance pour fixer les tarifs en vertu de la Loi. C'est là une question de droit susceptible d'appel en vertu de l'art. 62. Une décision relative à une requête qui oblige la Commission à interpréter les art. 28 et 31 de *The Gas Utilities Act*, soulève une question de droit pouvant mettre en cause la compétence de la Commission.

Cependant, les circonstances de la présente affaire ne permettent pas au tribunal qui examine l'ordonnance de la Commission d'établir si cette dernière a excédé sa compétence. Le libellé et le contenu de l'ordonnance de la Commission sont en effet d'une portée si limitée et d'une telle brièveté qu'il est impossible d'établir si les tarifs ont été fixés pour la période commençant le 1er octobre 1975. Cet argument de la compagnie ne peut donc être retenu.

La deuxième question en litige porte sur l'application de l'art. 8 de *The Administrative Procedures Act* aux présentes procédures; cette disposition oblige certains tribunaux administratifs à communiquer aux parties une décision écrite, exposant les conclusions de fait et les motifs sur lesquels elle est fondée; la décision de la Commission accordant l'augmentation provisoire de tarifs n'est pas conforme aux exigences de cet article. L'inobservation de l'art. 8 par la Commission comporte l'omission très grave d'exposer «les conclusions de fait sur lesquelles sa décision est fondée», de sorte qu'il est impossible pour les parties et pour le tribunal siégeant en révision de déterminer si, dans l'exercice de ses fonctions, la Commission a respecté ou excédé les limites de sa compétence qu'établit sa loi organique. Les appelantes ne trouvent aucun appui dans *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.* (1976), 2 A.R. 453, confirmé à [1977] 2 R.C.S. 822, où il fut jugé que pour être conformes à l'art. 8 de *The Administrative Procedures Act*, les motifs doivent être appropriés, pertinents et intelligibles, et doivent permettre à la partie concernée d'évaluer les possibilités d'appel. La Commission ne peut pas invoquer non plus le caractère particulier de l'ordonnance en question, savoir une ordonnance provisoire dont les dispositions prévoient la possibilité d'un remboursement des montants perçus sous son autorité, pour se soustraire

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Board revealed only conclusions without any hint of the reasoning process which led thereto. The result was that a reviewing tribunal could not with any assurance determine that the statutory mandates bearing upon the Board's process had been heeded.

As for the participation of The Public Utilities Board in these proceedings, there is no doubt that s. 65 of *The Public Utilities Board Act* confers upon the Board the right to participate on appeals from its decisions, but in the absence of a clear expression of intention on the part of the Legislature, this right is a limited one. The Board is given *locus standi* as a participant in the nature of an *amicus curiae* but not as a party. That this is so is made evident by s. 63(2) under which a distinction is drawn between "parties" who seek to appeal a decision of the Board or were represented before the Board, and the Board itself.

The policy of this Court is to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction.

Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of America Local 2142 (1973), 7 N.B.R. (2d) 41; *MacDonald v. The Queen* (1976), 29 C.C.C. (2d) 257; *Re Canada Metal Co. Ltd. et al. and MacFarlane* (1973), 1 O.R. (2d) 577; *Labour Relations Board of the Province of New Brunswick v. Eastern Bakeries Ltd.*, [1961] S.C.R. 72; *Labour Relations Board of Saskatchewan v. Dominion Fire Brick and Clay Products Ltd.*, [1947] S.C.R. 336; *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board* (1958), 18 D.L.R. (2d) 588; *Central Broadcasting Co. Ltd. v. Canada Labour Relations Board and International Brotherhood of Electrical Workers, Local Union No. 529*, [1977] 2 S.C.R. 112; *Canada Labour Relations Board v. Transair Ltd. et al.*, [1977] 1 S.C.R. 772, referred to.

APPEAL from a judgment of the Supreme Court of Alberta, Appellate Division[1], setting aside an order of The Public Utilities Board of the Province of Alberta granting an interim increase in rates pursuant to s. 52(2) of *The Public Utilities Board Act*, R.S.A. 1970, c. 302. Appeal dismissed.

[1] (1977), 2 A.R. 317.

à son obligation de rendre une décision motivée. L'ordonnance de la Commission ne comporte que des conclusions et est muette quant au raisonnement suivi pour y arriver, de sorte que le tribunal siégeant en révision ne peut établir avec certitude si la Commission a observé les exigences légales dans l'élaboration de sa décision.

En ce qui concerne la participation de The Public Utilities Board aux présentes procédures, il est évident que l'art. 65 de *The Public Utilities Board Act* confère à la Commission le droit de participer à l'appel de ses décisions, mais en l'absence d'indication précise de l'intention du législateur, ce droit est limité. La Commission a un *locus standi* et son droit de participer aux procédures d'appel s'apparente à celui d'un *amicus curiae* et non à celui d'une partie. Cela ressort clairement du par. 63(2) qui fait une distinction entre les «parties» qui interjettent appel de la décision de la Commission ou qui étaient représentées devant la Commission, et la Commission elle-même.

Cette Cour, à cet égard, a toujours voulu limiter le rôle du tribunal administratif dont la décision est contestée à la présentation d'explications sur le dossier dont il était saisi et d'observations sur la question de sa compétence, même lorsque la loi lui confère le droit de comparaître.

Jurisprudence: *Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of America Local 2142* (1973), 7 N.B.R. (2d) 41; *MacDonald c. La Reine* (1976), 29 C.C.C. (2d) 257; *Re Canada Metal Co. Ltd. et al. and MacFarlane* (1973), 1 O.R. (2d) 577; *Labour Relations Board of the Province of New Brunswick c. Eastern Bakeries Ltd.*, [1961] R.C.S. 72; *Labour Relations Board of Saskatchewan c. Dominion Fire Brick and Clay Products Ltd.*, [1947] R.C.S. 336; *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board* (1958), 18 D.L.R. (2d) 588; *Central Broadcasting Co. Ltd. c. Conseil canadien des relations du travail et la Fraternité internationale des ouvriers en électricité, Section locale nº 529*, [1977] 2 R.C.S. 112; *Conseil canadien des relations du travail c. Transair Ltd. et autres*, [1977] 1 R.C.S. 772.

POURVOI à l'encontre d'un arrêt de la Division d'appel de la Cour suprême de l'Alberta[1] infirmant une ordonnance de The Public Utilities Board de la province de l'Alberta qui accordait une augmentation provisoire de tarifs en vertu du par. 52(2) de *The Public Utilities Board Act*, R.S.A. 1970, chap. 302. Pourvoi rejeté.

[1] (1977), 2 A.R. 317.

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T. Mayson, Q.C., for the appellant Northwestern Utilities Ltd.

W. J. Major, Q. C., and *C. K. Sheard*, for the appellant Public Utilities Board of the Province of Alberta.

M. H. Patterson, Q. C., for the respondent.

The judgment of the Court was delivered by

ESTEY J.—This is an appeal by The Public Utilities Board for the Province of Alberta and Northwestern Utilities Limited from a decision of the Appellate Division of the Supreme Court setting aside an order of the Board granting an interim increase in rates pursuant to s. 52(2) of *The Public Utilities Board Act*, R.S.A. 1970, c. 302.

The majority of the Court of Appeal set aside the order and remitted it to the Board for reconsideration on two grounds:

(1) That the effect of the order was a contravention of s. 31 of *The Gas Utilities Act*, R.S.A. 1970, c. 158, in that Northwestern Utilities Limited was thereby granted recovery of losses incurred before the date of application, namely, the 20th of August 1975; and
(2) That the Board failed to comply with s. 8 of *The Administrative Procedures Act*, R.S.A. 1970, c. 2, by reason of its failure to give reasons for its decision.

The appellant, The Public Utilities Board (herein referred to as 'the Board'), is constituted under *The Public Utilities Board Act* to "deal with public utilities and the owners thereof as provided in this Act" (s. 28(1)), and is given more specific duties and powers with respect to gas utilities under *The Gas Utilities Act*. The appellant, Northwestern Utilities Limited (herein referred to as 'the Company'), is a gas utility regulated under these statutes.

The Board is by the latter statute directed to "fix just and reasonable ... rates, ... tolls or charges ..." which shall be imposed by the Company and other gas utilities and in connection therewith shall establish such depreciation and

T. Mayson, c.r., pour l'appelante Northwestern Utilities Ltd.

W. J. Major, c.r., et *C. K. Sheard*, pour l'appelante Public Utilities Board de la province de l'Alberta.

M. H. Patterson, c.r., pour l'intimée.

Le jugement de la Cour a été rendu par

LE JUGE ESTEY—Ce pourvoi est interjeté par The Public Utilities Board de la province de l'Alberta et Northwestern Utilities Limited à l'encontre d'un arrêt de la Division d'appel de la Cour suprême de l'Alberta annulant une ordonnance aux termes de laquelle la Commission accordait une augmentation provisoire de tarifs en vertu du par. 52(2) de *The Public Utilities Board Act*, R.S.A. 1970, chap. 302.

La majorité en Cour d'appel a infirmé l'ordonnance et renvoyé l'affaire devant la Commission pour deux motifs:

[TRADUCTION] (1) L'ordonnance produit un résultat qui contrevient à l'art. 31 de *The Gas Utilities Act*, R.S.A. 1970, chap. 158, car elle permet à Northwestern Utilities Limited de recouvrer des pertes subies avant la date de la requête, c.-à-d. le 20 août 1975; et
(2) La Commission n'a pas respecté l'art. 8 de *The Administrative Procedures Act*, R.S.A. 1970, chap. 2, en ne consignant pas les motifs de sa décision.

L'appelante, The Public Utilities Board (ci-après appelée la «Commission»), a été créée par *The Public Utilities Board Act* pour [TRADUCTION] «connaître des questions concernant les entreprises de services publics et leurs propriétaires, conformément à la présente loi» (par. 28(1)); *The Gas Utilities Act* lui confère en outre des devoirs et pouvoirs plus spécifiques à l'égard des entreprises de distribution de gaz. L'appelante Northwestern Utilities Limited (ci-après appelée la «Compagnie») est une entreprise de distribution de gaz régie par ces lois.

L'article 27 de *The Gas Utilities Act* habilite la Commission à [TRADUCTION] «fixer les tarifs, ... taxes ou droits ... justes et raisonnables» que la Compagnie et les autres entreprises de distribution de gaz seront autorisées à percevoir et, ce faisant,

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other accounting procedures as well as "standards, classifications [and] regulations . . ." for the service of the community by the gas utilities (s. 27, *The Gas Utilities Act*). In the establishment of these rates and charges, the Board is directed by s. 28 of the statute to "determine a rate base" and to "fix a fair return thereon". The Board then estimates the total operating expenses incurred in operating the utility for the period in question. The total of these two quantities is the 'total revenue requirement' of the utility during a defined period. A rate or tariff of rates is then struck which in a defined prospective period will produce the total revenue requirement. The whole process is simply one of matching the anticipated revenue to be produced by the newly authorized future rates to future expenses of all kinds. Because such a matching process requires comparisons and estimates, a period in time must be used for analysis of past results and future estimates alike. The fiscal year of the utility is generally found to be a convenient but not a mandatory period for these purposes. It is a process based on estimates of future expenses and future revenues. Both according to the evidence fluctuate seasonally and both vary according to many uncontrollable forces such as weather variations, cost of money, wage rate settlements and many other factors. Thus the rate when finally established will be such as the Board deems just and reasonable to allow the recovery of the expenses incurred by a utility in supplying gas to its customers, together with a fair return on the investment devoted to the enterprise. We are here concerned only with the rate establishing process and, hence, this summation of the Board's functions and powers is limited to that aspect of its statutory operations.

While the statute does not precisely so state, the general pattern of its directing and empowering provisions is phrased in prospective terms. Apart from s. 31 there is nothing in the Act to indicate any power in the Board to establish rates retrospectively in the sense of enabling the utility to recover a loss of any kind which crystallized prior to the date of the application (*vide City of*

à déterminer la méthode d'amortissement et autres procédures comptables de même que les [TRADUCTION] «normes, catégories [et] règlements» applicables aux entreprises de distribution de gaz en tant que services publics. Pour établir ces tarifs et droits, la Commission doit, en vertu de l'art. 28 de la Loi, [TRADUCTION] «établir une base de tarification [et] fixer un taux de rendement convenable». La Commission doit ensuite évaluer les dépenses totales d'exploitation de l'entreprise pendant la période considérée. Le total de ces deux éléments forme le «revenu total nécessaire» à l'entreprise pour une période donnée. Le tarif est alors établi pour la période à venir de façon à produire le revenu total nécessaire. En fait, il s'agit de faire correspondre les revenus que produiront les nouveaux tarifs autorisés pour la période à venir au total des diverses dépenses futures. Etant donné que ce calcul se fait sur la base de comparaisons et d'estimations, l'analyse des résultats obtenus dans le passé et des estimations faites pour l'avenir doit être fondée sur une période de temps précise. Sans être la règle, l'année d'imposition de l'entreprise est généralement considérée une base adéquate. Le processus est fondé sur une estimation des dépenses et revenus futurs. Selon la preuve, ces deux éléments varient d'une saison à l'autre et dépendent de facteurs incontrôlables tels les conditions météorologiques, le coût de l'argent, les ententes salariales, et ainsi de suite. Ainsi, le tarif établi par la Commission doit être celui qu'elle juge juste et raisonnable pour permettre le recouvrement des dépenses engagées par une entreprise de distribution de gaz pour desservir ses clients et la réalisation d'un taux de rendement convenable sur l'investissement dans l'entreprise. La seule question qui nous occupe en l'espèce est la méthode de détermination des tarifs et, en conséquence, cet aperçu des fonctions et pouvoirs de la Commission se limite à cet aspect du rôle que lui prescrit la loi.

Bien que la Loi ne le dise pas expressément, ses prescriptions et dispositions habilitantes sont rédigées en termes prospectifs. Mis à part l'art. 31, rien dans la Loi n'indique que la Commission ait le pouvoir d'établir rétroactivement des tarifs de façon à permettre à l'entreprise de recouvrer des pertes d'aucun genre subies avant la date de la requête. (Voir l'arrêt *Ville d'Edmonton et autres*

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Edmonton et al. v. Northwestern Utilities Limited[2], *per* Locke J. at pp. 401, 402).

The rate-fixing process was described before this Court by the Board as follows:

> The PUB approves or fixes utility rates which are estimated to cover expenses plus yield the utility a fair return or profit. This function is generally performed in two phases. In Phase I the PUB determines the rate base, that is the amount of money which has been invested by the company in the property, plant and equipment plus an allowance for necessary working capital all of which must be determined as being necessary to provide the utility service. The revenue required to pay all reasonable operating expenses plus provide a fair return to the utility on its rate base is also determined in Phase I. The total of the operating expenses plus the return is called the revenue requirement. In Phase II rates are set, which, under normal temperature conditions are expected to produce the estimates of "forecast revenue requirement". These rates will remain in effect until changed as the result of a further application or complaint or the Board's initiative. Also in Phase II existing interim rates may be confirmed or reduced and if reduced a refund is ordered.

The statutory pattern is founded upon the concept of the establishment of rates *in futuro* for the recovery of the total forecast revenue requirement of the utility as determined by the Board. The establishment of the rates is thus a matching process whereby forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of *The Gas Utilities Act* that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the Act which make this clear and I take but one example, found in s. 35, which provides:

> (1) No change in any existing rates . . . shall be made by a . . . gas utility . . . until such changed rates or new rates are approved by the Board.
>
> (2) Upon approval, the changed rates . . . come into force on a date to be fixed by the Board and the Board

[2] [1961] S.C.R. 392.

c. Northwestern Utilities Limited[2], le juge Locke, aux pp. 401 et 402.)

Voici en quels termes la Commission a décrit à cette Cour sa méthode de détermination des tarifs:

> [TRADUCTION]—La PUB approuve ou fixe pour les services publics des tarifs destinés à couvrir les dépenses et à permettre à l'entreprise d'obtenir un taux de rendement ou profit convenable. Le processus s'accomplit en deux étapes. Dans la première étape, la PUB établit une base de tarification en calculant le montant des fonds investis par la compagnie en terrains, usines et équipements, plus le montant alloué au fonds de roulement, sommes dont il faut établir la nécessité dans l'exploitation de l'entreprise. C'est également à cette première étape qu'est calculé le revenu nécessaire pour couvrir les dépenses d'exploitation raisonnables et procurer un rendement convenable sur la base de tarification. Le total des dépenses d'exploitation et du rendement donne un montant appelé le revenu nécessaire. Dans une deuxième étape, les tarifs sont établis de façon à pouvoir produire, dans des conditions météorologiques normales, «le revenu nécessaire prévu». Ces tarifs restent en vigueur tant qu'ils ne sont pas modifiés à la suite d'une nouvelle requête ou d'une plainte, ou sur intervention de la Commission. C'est également à cette seconde étape que les tarifs provisoires sont confirmés ou réduits et, dans ce dernier cas, qu'un remboursement est ordonné.

L'économie de la législation repose sur le principe que la détermination des tarifs pour l'avenir doit permettre à l'entreprise de percevoir intégralement le revenu nécessaire prévu calculé par la Commission. La détermination des tarifs consiste donc à faire correspondre le montant des revenus prévus produits par les tarifs projetés au revenu total nécessaire à l'entreprise. Il ressort clairement de plusieurs dispositions de *The Gas Utilities Act* que la Commission n'agit que pour l'avenir et ne peut fixer des tarifs qui permettraient à l'entreprise de recouvrer des dépenses engagées antérieurement et que les tarifs précédents n'avaient pas suffi à compenser. Plusieurs dispositions de la Loi le confirment d'ailleurs, notamment l'art. 35:

> [TRADUCTION] (1) Les entreprises de distribution de gaz . . . ne doivent pas modifier les tarifs en vigueur . . . avant d'avoir obtenu l'approbation de la Commission.
>
> (2) Après leur approbation, les tarifs modifiés . . . entrent en vigueur à la date fixée par la Commission et

[2] [1961] R.C.S. 392.

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may either upon written complaint or upon its own initiative herein determine whether the imposed increases, changes or alterations are just and reasonable.

Section 32 likewise refers to rates "to be imposed thereafter by a gas utility". The 1959 version of the legislation before the Court in this proceeding was examined by the Alberta Court of Appeal in *City of Calgary and Home Oil Co. Ltd. v. Madison Natural Gas Co. Ltd. and British American Utilities Ltd.*[3] wherein Johnson J.A. observed at p. 661:

The powers of the Natural Gas Utilities Board have been quoted above and the Board's function was to determine "the just and reasonable price" or prices to be paid. It was to deal with rates prospectively and having done so, so far as that particular application is concerned, it ceased to have any further control. To give the Board retrospective control would require clear language and there is here a complete absence of any intention to so empower the Board.

Vide also *Regina v. Board of Commissioners of Public Utilities (N.B.), Ex parte Moncton Utility Gas Ltd.*[4], at p. 710; *Bradford Union v. Wilts*[5], at p. 616.

There is but one exception in this statutory pattern and that is found in s. 31 which is critical in these proceedings. It is convenient to set it out in full.

It is hereby declared that, in fixing just and reasonable rates, the Board may give effect to such part of any excess revenues received or losses incurred by an owner of a gas utility after an application has been made to the Board for the fixing of rates as the Board may determine has been due to undue delay in the hearing and determining of the application.

It should be noted that s. 31 has been amended by s. 5 of *The Attorney General Statutes Amendment Act, 1977*, 1977 (Alta.), c. 9, which received Royal Assent on May 18, 1977. However, s. 5(3) of that Act provides that s. 31 "as it stood immediately before the commencement of" s. 5 ". . . continues to apply to proceedings initiated . . ." before

[3] (1959), 19 D.L.R. (2d) 655.
[4] (1966), 60 D.L.R. (2d) 703.
[5] (1868), L.R. 3 Q.B. 604.

cette dernière peut, à la suite d'une plainte écrite ou d'office, déterminer si les augmentations ou modifications accordées sont justes et raisonnables.

L'article 32 parle également de tarifs [TRADUCTION] «imposés à l'avenir par l'entreprise de distribution de gaz». La législation en cause devant cette Cour a fait l'objet, dans sa version de 1959, des remarques suivantes du juge Johnson de la Cour d'appel de l'Alberta dans l'arrêt *City of Calgary and Home Oil Co. Ltd. v. Madison Natural Gas Co. Ltd. and British American Utilities Ltd.*[3], à la p. 661:

[TRADUCTION] Les pouvoirs de The Natural Gas Utilities Board ont été précisés plus haut. La Commission a le devoir de fixer les «prix justes et raisonnables» à payer. Elle doit établir les tarifs pour l'avenir et, ceci fait, elle n'a plus compétence aux fins de cette requête. Pour que la Commission ait le pouvoir de prendre des mesures rétroactives, il faudrait que la Loi le prévoie expressément; or, rien en l'espèce ne révèle l'intention de conférer un tel pouvoir à la Commission.

Voir également *Regina v. Board of Commissioners of Public Utilities (N.B.), Ex parte Moncton Utility Gas Ltd.*[4], à la p. 710; *Bradford Union v. Wilts*[5], à la p. 616.

Il existe cependant une disposition importante qui se distingue du reste de la Loi sur cette question; il s'agit de l'art. 31, qui est capital en l'espèce. Il convient de le citer intégralement:

[TRADUCTION] Il est par les présentes déclaré qu'en fixant des tarifs justes et raisonnables, la Commission peut tenir compte de la partie des excédents de revenu perçus ou des pertes subies par le propriétaire d'une entreprise de distribution de gaz après sa demande de nouveaux tarifs, si la Commission estime que ces excédents ou pertes sont imputables à un retard indu à entendre et à trancher la demande.

Il convient de souligner que l'art. 31 a été modifié par l'art. 5 de *The Attorney General Statutes Amendment Act, 1977*, 1977 (Alta.), chap. 9, qui a reçu la sanction royale le 18 mai 1977. Cependant, le par. 5(3) de la Loi dispose que l'art. 31 [TRADUCTION] «existant avant l'entrée en vigueur de [l'art. 5] continue de s'appliquer aux

[3] (1959), 19 D.L.R. (2d) 655.
[4] (1966), 60 D.L.R. (2d) 703.
[5] (1868), L.R. 3 Q.B. 604.

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May 18, 1977. Accordingly, this case stands to be determined in accordance with s. 31 as set out above.

The interpretative difficulties raised by s. 31 are manifold. For one thing, the word 'losses' which is not defined in the Act is employed with reference to the Board's power to establish rates with respect to the period after an application has been made and before the Board has fully disposed of the application by taking into account "excess revenues and losses" which the Board determines have been "due to undue delay in the hearing and determination of the application". It is in my view apparent once the statute is examined as a whole that 'losses' as the word is employed in s. 31 does not refer to accounting losses in the sense of a net loss occurring in a defined fiscal period but rather refers to the loss of revenue suffered by a utility during a defined period by reason of the delay in the imposition during that period of the proposed increased rates. The word in short is an abbreviation for 'lost revenue' which may indeed be suffered by a utility during a period when the utility is not in a net loss position in the accounting sense of that term. This Court had occasion to consider s. 31 collaterally in *City of Edmonton et al. v. Northwestern Utilities Limited, supra.* Locke J. writing on behalf of the whole Court on this point so interpreted and applied the word "losses" as it appears in this section.

Much of the difficulty encountered before the Board and again reflected in the judgment of the Court of Appeal has arisen by the use of the expression 'loss' sometimes to refer to a net loss for a period in the past and sometimes by applying the term to a shortfall of revenue in the sense in which I believe the Legislature uses the term in s. 31. This difficulty appears to have been obviated by the new s. 31 which is not now before the Court (*vide The Attorney General Statutes Amendment Act, 1977, supra*).

Section 52(2) of *The Public Utilities Board Act* should also be noted:

The Board may, instead of making an order final in the first instance, make an interim order and reserve

procédures instituées . . .» avant le 18 mai 1977. Le présent litige doit donc être tranché en fonction de la version précitée de l'art. 31.

Les problèmes d'interprétation que soulève l'art. 31 sont nombreux. Par exemple, le mot «pertes», qui n'est pas défini dans la Loi, est utilisé dans le contexte du pouvoir de la Commission de fixer des tarifs pour la période qui suit la date de la demande et qui précède la décision finale de la Commission sur le sujet en tenant compte des «excédents de revenu et des pertes» qu'elle considère «imputables à un retard indu à entendre et à trancher la demande». Il est à mon avis évident, dans le contexte général de la Loi, que le mot «pertes» à l'art. 31 ne renvoie pas aux pertes comptables au sens d'une perte nette subie au cours d'une année d'imposition, mais plutôt à la perte de revenu subie par l'entreprise au cours d'une période précise en raison du retard à mettre en vigueur, durant cette période, les augmentations projetées. Il s'agit en fait d'une façon abrégée de décrire la «perte de revenu» que peut subir une entreprise durant une certaine période sans que pour autant elle subisse une perte nette au sens comptable de cette expression. Cette Cour a déjà eu l'occasion d'étudier incidemment le sens de l'art. 31 dans l'arrêt *Ville d'Edmonton et autres c. Northwestern Utilities Limited*, précité. Exposant l'opinion de la Cour à ce sujet, le juge Locke a interprété et appliqué de cette façon le mot «pertes» employé dans ledit article.

La difficulté éprouvée devant la Commission, qui se reflète aussi dans le jugement de la Cour d'appel, vient en grande partie du fait que le mot «perte» est parfois utilisé pour désigner une perte nette subie au cours d'une période antérieure, et parfois pour désigner un manque à gagner (sens que lui donne, à mon avis, le législateur à l'art. 31). Il semble que le texte du nouvel art. 31, non applicable en l'espèce, ait fait disparaître cette difficulté (voir *The Attorney General Statutes Amendment Act, 1977*, précitée).

Le paragraphe 52(2) de *The Public Utilities Board Act* mérite également d'être cité:

[TRADUCTION] La Commission peut prononcer une ordonnance provisoire, au lieu de rendre une ordonnance

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further direction, either for an adjourned hearing of the matter or for further application.

Section 54 provides in similar language the authority for the Board to make such interim orders *ex parte*. These interim orders are couched in the same terms as the final or basic orders establishing rates and tariffs and hence are likewise prospective.

Against this statutory background a brief outline of the historical facts of this proceeding and its origins bring the two issues now before the Court into sharper focus. Commencing on August 20, 1974, the Company filed an application for an order determining the rate base and fixing a fair return thereon and approving the rates and charges for the natural gas supplied by the Company to its customers. The application made reference to the powers under s. 31 by asking for an order "giving effect to such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application". Finally the application sought an order fixing interim rates pending the establishment of "final rates". As a result of this application several interim orders were issued between November 15, 1974, and June 30, 1975. In response to the application of August 20, 1974, the Board by order made on September 15, 1975, established the rate base, a fair return thereon and the total utility revenue requirement at $72,141,000. These items were respectively found and included in the order on the basis of "actual 1974" figures and "forecast 1975" figures. The Board then directed the Company to file a schedule of rates "designed to generate the foregoing total utility revenue requirements approved by the Board".

The practice and terminology historically adopted by the Board in the discharge of its statutory functions are no doubt clear to the industry and to persons attending upon the Board in the discharge of its functions but leaves something to be desired in the sense that the terminology does not precisely fit that employed by the legislation to which reference has been made. It is clear, however, that in its order with respect to the August 1974 application,

définitive, et remettre sa décision à une audition ultérieure de la demande ou à la présentation d'une nouvelle demande.

L'article 54 habilite la Commission, en des termes semblables, à rendre de telles ordonnances provisoires *ex parte*. Ces ordonnances provisoires sont rédigées de la même façon que les ordonnances définitives ou initiales fixant les tarifs et, comme elles, ne s'appliquent que pour l'avenir.

Cet historique de la législation doit être complété d'un rappel des faits à l'origine de ce pourvoi afin de bien mettre en évidence les deux questions en litige devant cette Cour. Le 20 août 1974, la Compagnie demandait une ordonnance établissant une base de tarification et un rendement convenable et approuvant les tarifs et droits qu'elle voulait imposer à ses clients pour le gaz naturel qu'elle distribuait. Se référant aux pouvoirs prévus à l'art. 31, elle demandait une ordonnance [TRADUCTION] «tenant compte de la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande». En outre, elle demandait une ordonnance établissant des tarifs provisoires jusqu'à la fixation des «tarifs définitifs». En conséquence, plusieurs ordonnances provisoires ont été rendues entre le 15 novembre 1974 et le 30 juin 1975. En réponse à la requête du 20 août 1974, la Commission rendait, le 15 septembre 1975, une ordonnance qui établissait une base de tarification et un rendement convenable et fixait le revenu total nécessaire à l'entreprise à $72,141,000. Ces montants inclus dans l'ordonnance étaient calculés en fonction des «données réelles pour 1974» et des «prévisions pour 1975». La Commission a ensuite ordonné à la Compagnie de produire un tarif [TRADUCTION] «apte à produire le revenu total nécessaire à l'entreprise approuvé par la Commission».

Je ne doute pas que les usages et le vocabulaire adoptés par la Commission dans l'exercice des devoirs que lui confère la Loi soient clairs pour les gens de l'industrie ou les personnes qui comparaissent devant la Commission, mais la terminologie employée suscite une certaine confusion car elle diffère de celle de la législation, à laquelle j'ai fait référence plus haut. Toutefois, il est clair que c'est en fonction de la période à venir que la Commis-

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the Board has attempted to establish in the prospective sense those rates which the Company will require to enable it to carry on its business as a gas utility in the future and until such further and other rates are established by the Board. Had the Company then responded to the September 15 order by filing a proposed schedule of rates the Board would no doubt in completion of its statutory response to the August 1974 application by the Company have established the appropriate schedule of rates to be brought into effect by the Company in its billings from and after a date prospectively prescribed by the Board.

The complication which gives rise to these proceedings occurred on August 20, 1975, when the Company filed with the Board an application (not to be confused with the application filed on August 20, 1974) for an order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by Northwestern Utilities Limited to its customers"; together with an application on September 25, 1975, for an interim order "approving changes in existing rates, tolls or charges for gas supplied and services rendered by Northwestern Utilities Limited to its customers pending final determination of the matter". The application of 1975 recites the history of the 1974 application and states that the operating costs and gas costs of the Company "have increased substantially over the amounts included in the 1974 application and continue to increase". After reciting that the Board in response to the 1974 application had awarded the applicant "interim refundable rates", the 1975 application went on to state:

> The existing rates charged by the Applicant for natural gas do not produce revenues sufficient to provide for its present or prospective proper operating and depreciation expense and a fair return on the property used in the service to the public.

Therefore the Company went on to apply for an order determining the rate base, and a fair return thereon, and fixing and approving rates for natural gas supplied by the Company to its customers. The

sion a essayé, dans l'ordonnance relative à la requête du 20 août 1974, de fixer les tarifs devant permettre à la Compagnie de poursuivre l'exploitation de son entreprise de distribution de gaz jusqu'à ce que la Commission fixe de nouveaux tarifs. Si la Compagnie avait produit un projet de tarif, en réponse à l'ordonnance du 15 septembre, la Commission se serait sans nul doute acquittée des devoirs que lui impose la Loi pour la requête d'août 1974 en fixant le tarif approprié que la Compagnie aurait pu commencer à appliquer dans sa facturation à partir d'une date prescrite par la Commission de façon prospective.

Le litige actuel remonte au 20 août 1975, date à laquelle la Compagnie a présenté à la Commission une requête (à ne pas confondre avec la requête produite le 20 août 1974) en vue d'obtenir une ordonnance [TRADUCTION] «approuvant les modifications aux tarifs, taxes et droits actuellement perçus par Northwestern Utilities Limited pour le gaz distribué et les services fournis à ses clients»; cette requête fut suivie d'une autre, datée du 25 septembre 1975 pour obtenir une ordonnance provisoire [TRADUCTION] «approuvant, jusqu'à ce qu'une décision définitive soit rendue, les modifications aux tarifs, taxes et droits actuellement perçus par Northwestern Utilities Limited pour le gaz distribué et les services fournis à ses clients». La requête de 1975 fait l'historique de la requête de 1974 et souligne que les frais d'exploitation de la Compagnie et le coût du gaz [TRADUCTION] «ont considérablement augmenté comparativement aux montants indiqués dans la requête de 1974 et continuent d'augmenter». Après avoir mentionné qu'à la suite de la requête présentée en 1974, la Commission avait accordé à la requérante des [TRADUCTION] «tarifs provisoires remboursables», la requête de 1975 allègue:

> [TRADUCTION] Les tarifs actuellement perçus par la requérante pour son gaz naturel ne produisent pas un revenu suffisant pour lui permettre de faire face à ses dépenses actuelles et futures d'exploitation et d'amortissement et d'obtenir un taux de rendement convenable sur l'investissement utilisé au service du public.

La Compagnie a alors demandé une ordonnance qui établisse une base de tarification et un rendement convenable, et fixe et approuve les tarifs à percevoir par la Compagnie pour la distribution de

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Company sought as well an order giving effect to "such part of any losses incurred by the applicant as may be due to any undue delay in the hearing and determining of the application", apparently paraphrasing s. 31 of *The Gas Utilities Act*. The 1975 application seeks as well interim rates "pending the fixing of final rates".

It is also relevant to note in passing that the 1974 application indeed had its own roots in a prior procedure before the Board initiated by the Board itself under s. 27 of *The Gas Utilities Act* in 1974. In June 1974, the Company applied for an interim rate increase and after a hearing in July 1974 the application was denied on August 19, 1974, and the application of August 20, 1974, was thereupon filed.

By its order of October 1, 1975, the Board granted an interim increase in rates the effect of which was to allow the Company to receive $2,785,000 in excess of its revenues for 1975 which would have been received under the then existing rates. The question immediately arises as to whether this sum represents increased expenses to be incurred by the Company for the period after the interim rates became effective (October 1, 1975) or whether it represents expenses incurred and unrecovered in the past. It was from this interim order that the City of Edmonton (herein referred to as 'the City') appealed to the Appellate Division of the Supreme Court of Alberta pursuant to s. 62 of *The Public Utilities Board Act*:

> (1) Subject to subsection (2) [the requirement of leave], upon a question of jurisdiction or upon a question of law, an appeal lies from the Board to the Appellate Division of the Supreme Court of Alberta.

The Appellate Division of the Supreme Court of Alberta set aside the Board order of October 1, 1975, and referred the matter to the Board "for further consideration and redetermination". One preliminary argument can be disposed of at the outset. It was argued in the Courts below, as well

gaz naturel. La Compagnie a également demandé une ordonnance tenant compte de [TRADUCTION] «la partie des pertes subies par la requérante imputables à un retard indu à entendre et à trancher la demande», paraphrasant apparemment l'art. 31 de *The Gas Utilities Act*. La requête de 1975 demandait en outre une ordonnance fixant des tarifs provisoires applicables [TRADUCTION] «jusqu'à l'établissement de tarifs définitifs».

Il est également pertinent de souligner ici que la requête présentée en 1974 résulte d'une procédure antérieure entamée la même année par la Commission elle-même en vertu de l'art. 27 de *The Gas Utilities Act*. En effet, en juin 1974, la Compagnie avait demandé à la Commission de fixer une augmentation provisoire de tarifs; après une audience tenue en juillet 1974, la Commission a rejeté cette requête, le 19 août 1974, et la Compagnie est revenue à la charge en déposant sa requête du 20 août 1974.

Dans son ordonnance du 1er octobre 1975, la Commission a accordé une augmentation provisoire de tarifs permettant à la Compagnie de percevoir un revenu supérieur de $2,785,000 à celui qu'elle aurait normalement perçu en 1975. Il faut immédiatement se demander si cette différence correspond à une augmentation des dépenses après la date d'entrée en vigueur de l'augmentation provisoire de tarifs (soit le 1er octobre 1975) ou à des dépenses déjà engagées mais non recouvrées. C'est précisément de cette ordonnance provisoire dont la ville d'Edmonton (ci-après appelée la «Ville») a interjeté appel devant la Division d'appel de la Cour suprême de l'Alberta en vertu de l'art. 62 de *The Public Utilities Board Act*, qui dispose:

> [TRADUCTION] (1) Sous réserve du paragraphe (2) [l'autorisation d'appel], les décisions de la Commission sont susceptibles d'appel à la Division d'appel de la Cour suprême de l'Alberta sur une question de compétence ou de droit.

La Division d'appel de la Cour suprême de l'Alberta a infirmé l'ordonnance de la Commission rendue le 1er octobre 1975 et lui a renvoyé l'affaire [TRADUCTION] «pour nouvel examen et décision». On peut tout de suite trancher une question préliminaire: on a soutenu devant les tribunaux d'ins-

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as in this Court, that the interim order under appeal (dated October 1, 1975) was made pursuant to the 1974 rate application, either as a variance of the 1974 order pursuant to s. 56 of *The Public Utilities Board Act*, or as an interim order in respect of the 1974 application. That submission, whatever its effect, was rejected by the Court of Appeal and must be rejected here. On the face of the interim order is found a reference to "the application of N.U.L. dated the 20th day of August, 1975". That reference, when read with the transcript of the evidence at the hearing leaves no doubt that the interim order was made with respect to the 1975 application which clearly was an independent application to establish, pursuant to the aforementioned sections of *The Gas Utilities Act*, the statutory prerequisites to a new tariff of rates, and then a new tariff of rates.

I turn then to the first issue as to whether the Board by its interim order of October 1, 1975, has offended the provisions of s. 31 of *The Gas Utilities Act* by granting as alleged by the City an order permitting the recovery of losses incurred before the date of the application, August 20, 1975. It was not argued before this Court that the Board could not through s. 31 reach back to August 20, 1975, and grant a rate increase to recover costs thereafter incurred. The recitals to the order of October 1975 make it difficult to determine whether in fact the Board has invoked s. 31 in the interim rates established by the order or whether the Board has simply made an interim order under s. 51(2) of *The Public Utilities Board Act*. We need not determine the answer to that question in order to deal with this issue.

The issue is at this stage very narrow. No contest is raised as to the validity of the September 15, 1975, order nor the various interim rates authorized in the 1974 application. The issue is simply whether or not the Company by not applying in the 1974 application for a further interim order has caused the Board to respond to the new application in 1975 in such a way as to authorize a new tariff which when implemented by the Company will have the effect of recovering from future gas consumers revenue losses incurred by the

tance inférieure et devant cette Cour que l'ordonnance provisoire (du 1er octobre 1975) contestée en appel faisait suite à la requête présentée en 1974 et constituait soit une modification de l'ordonnance rendue en 1974 en vertu de l'art. 56 de *The Public Utilities Board Act* soit une ordonnance provisoire se rapportant à la requête faite en 1974. Nous devons, comme la Cour d'appel, rejeter cet argument sans en examiner la portée. L'ordonnance provisoire mentionne «la requête de NUL en date du 20 août 1975». Cette mention, et la transcription de la preuve présentée à l'audition, indiquent clairement que l'ordonnance provisoire suit la requête présentée en 1975; cette dernière était totalement indépendante et visait à fixer, conformément aux articles susmentionnés de *The Gas Utilities Act*, les bases légales d'un nouveau tarif et ledit nouveau tarif.

J'en viens à la première question en litige: l'ordonnance provisoire rendue par la Commission le 1er octobre 1975 contrevient-elle à l'art. 31 de *The Gas Utilities Act* en permettant, selon la Ville, le recouvrement de pertes subies avant la présentation de la requête, le 20 août 1975? On n'a pas soutenu devant cette Cour que la Commission n'avait pas le pouvoir, en vertu de l'art. 31, de faire ses calculs à partir du 20 août 1975 et d'accorder une augmentation de tarifs pour couvrir les dépenses engagées après cette date. Les attendus de l'ordonnance d'octobre 1975 ne permettent pas d'établir si la Commission s'est fondée sur l'art. 31 pour fixer une augmentation provisoire ou a simplement rendu une ordonnance provisoire en vertu du par. 51(2) de *The Public Utilities Board Act*. Il n'est pas nécessaire de trancher cette question pour régler le point en litige.

La question soumise à cette Cour est très limitée. La validité de l'ordonnance rendue le 15 septembre 1975 et des nombreuses augmentations provisoires accordées à la suite de la requête présentée en 1974 n'est pas contestée. Il s'agit uniquement de déterminer si, en ne demandant pas d'ordonnance provisoire supplémentaire dans sa requête de 1974, la Compagnie a amené la Commission à répondre à la nouvelle requête de 1975 de manière à autoriser des tarifs qui auraient pour effet de faire supporter par les nouveaux consom-

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Company with respect to gas deliveries made to consumers prior to the date of the application in question (August 20, 1975) or prior to the advent of the October 1, 1975, rates but in a manner not authorized by s. 31.

The Appellate Division of the Supreme Court of Alberta in both the judgments of Clement J.A. and McDermid J. A., as well as counsel before this Court, devoted a considerable amount of attention to the accounting evidence filed by the Company with reference to the total revenue requirement of the Company in the years 1974 and 1975 and to the possibility that the inclusion in the rate base or the operating expenses established in Phase I of the 1975 application of the additional expenses which gave rise to the 1975 application, will have the effect of violating or going beyond s. 31 by authorizing rates which will have the effect of recovering past losses. We are here not concerned with capitalized losses because there is no suggestion that the rate base will be enlarged by the inclusion of any historical loss in the sense of an accounting deficit in prior fiscal intervals but rather with revenue losses other than those which may be recovered pursuant to s. 31 and which relate to the period from and after August 20, 1975. These losses of course have no relationship to a rate base computed and established pursuant to s. 28 of *The Gas Utilities Act*. We are concerned only with whether or not the Board in its processes has determined the total operating expenses for some period, as well as the fair return on the rate base, so as to enable the Board to calculate prospectively the anticipated total revenue requirement of the utility and thereby establish rates which prospectively will produce future revenues to match the estimated future total revenue requirement.

This procedure was the subject of comment by Porter J.A. in *Re Northwestern Utilities Ltd.*[6] at p. 290, and which comments I find apt in the circumstances now before us:

One effect of this ruling is that future consumers will have to pay for their gas a sum of money which equals that which consumers prior to August 31, 1959 ought to have paid but did not pay for gas they had used. In

[6] (1960), 25 D.L.R. (2d) 262.

mateurs de gaz les pertes de revenu sur le gaz livré avant la date de la requête (soit le 20 août 1975) ou avant la mise en vigueur des tarifs du 1er octobre 1975, mais d'une façon qui n'est pas autorisée par l'art. 31.

Les juges Clement et McDermid, qui ont rendu le jugement de la Division d'appel de la Cour suprême de l'Alberta, et les avocats devant cette Cour se sont longuement penchés sur la preuve comptable soumise par la Compagnie au sujet du revenu total nécessaire pour les années 1974 et 1975 et sur la possibilité que l'inclusion des dépenses supplémentaires à l'origine de la requête de 1975 dans la base de tarification ou dans les dépenses d'exploitation établies dans le cadre de la première étape de l'étude de la requête de 1975 contrevienne à l'art. 31 en autorisant des tarifs qui permettaient de compenser des pertes passées. Il ne s'agit pas de pertes capitalisées, car on n'a pas prétendu que la base de tarification avait été augmentée par l'inclusion d'une perte passée, au sens d'un déficit comptable d'années d'imposition précédentes; il s'agit plutôt de pertes de revenu autres que celles visées par l'art. 31 et qui auraient été subies après le 20 août 1975. Il est bien évident que ces pertes n'ont aucun lien avec la base de tarification calculée et établie en conformité de l'art. 28 de *The Gas Utilities Act*. La seule question à trancher à cet égard est de savoir si la Commission a établi les dépenses totales d'exploitation pour une période donnée et le rendement convenable sur la base de tarification afin d'être en mesure de calculer, pour l'avenir, le revenu total nécessaire à l'entreprise et donc fixer des tarifs pouvant produire suffisamment de revenus dans l'avenir pour correspondre au revenu total nécessaire ainsi déterminé.

Cette façon de procéder a fait faire au juge Porter, dans l'arrêt *Re Northwestern Utilities Ltd.*[6] à la p. 290, un commentaire qui me semble pertinent en l'espèce:

[TRADUCTION] Cette décision a notamment l'effet de faire payer aux nouveaux consommateurs de gaz une somme égale à ce que les consommateurs desservis avant le 31 août 1959 auraient dû payer, mais n'ont pas payé,

[6] (1960), 25 D.L.R. (2d) 262.

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short, the undercharge to one group of consumers for gas used in the past is to become an overcharge to another group on gas it uses in the future. When the Board capitalized this sum, it made all the future consumers debtors to the company for the total amount of the deficiency, payable ratably with interest from their respective future gas consumption.

It is conceded of course that the Act does not prevent the Board from taking into account past experience in order to forecast more accurately future revenues and expenses of a utility. It is quite a different thing to design a future rate to recover for the utility a 'loss' incurred or a revenue deficiency suffered in a period preceding the date of a current application. A crystallized or capitalized loss is, in any case, to be excluded from inclusion in the rate base and therefore may not be reflected in rates to be established for future periods.

The evidence submitted by the Company on the hearing of the 1975 application centred largely upon the urgent need for interim refundable rates by which the Company;

> can recover its costs of service and earn an adequate return on its utility assets for the year 1975. If the interim rates requested are nor granted, the costs of providing natural gas service would not be fully recovered.

The evidence goes on to outline the utility income under existing rates for the years 1975 and 1976 and it is stated that these rates unless augmented by interim rates as proposed will produce a shortfall in revenue of approximately $700,000 per month. The accounts so filed reveal computations which show the need for an additional $2.785 million for the year 1975 of which operating expenses represent $2.105 million. Unhappily, the record does not reveal whether all the components of the additional $2.785 million are recurring expenses and costs, or legitimate demands for return on capital, which will run evenly into the future. It may be that in the quarterly period of 1975 remaining at the time of the order, these projections will exceed or be less than the actual expenses to be incurred in that very quarterly period. On this the evidence is strangely silent. The

pour le gaz qu'ils ont utilisé. Bref, une perception insuffisante dans le passé à l'égard d'un groupe de consommateurs de gaz entraîne une surcharge à l'égard d'un autre groupe de consommateurs pour le gaz qu'il utilisera à l'avenir. En capitalisant cette somme, la Commission a rendu tous les consommateurs éventuels de gaz débiteurs envers la Compagnie d'un montant correspondant au manque à gagner avec intérêts, à payer en proportion de leur consommation future.

Il est admis que la Loi n'empêche pas la Commission de tenir compte de l'expérience passée pour mieux évaluer les revenus et les dépenses à venir d'une entreprise de services publics. Mais ce n'est pas la même chose d'établir un tarif qui permette à l'entreprise de compenser une «perte» ou une insuffisance de revenus subie au cours d'une période antérieure à la date de la requête considérée. Une perte identifiée ou capitalisée doit, de toute façon, être exclue de la base de tarification et, en conséquence, elle ne peut se refléter dans les tarifs établis pour une période à venir.

La preuve fournie par la Compagnie à l'audition de la requête de 1975 a principalement porté sur le besoin urgent de tarifs remboursables pour lui permettre

> [TRADUCTION]de recouvrer ses frais d'exploitation et d'obtenir un rendement convenable sur son investissement pour l'année 1975. Si les tarifs provisoires demandés ne sont pas accordés, le prix du service de distribution de gaz naturel ne sera pas complètement couvert.

En ce qui concerne les revenus produits par les tarifs prévus pour les années 1975 et 1976, la preuve révèle qu'à moins d'être augmentés par les tarifs provisoires proposés, ils entraîneront un manque à gagner d'environ $700,000 par mois. La preuve comptable comprend en outre des calculs établissant le besoin de $2,785,000 supplémentaires pour l'année 1975, dont $2,105,000 pour les frais d'exploitation. Malheureusement, le dossier n'indique pas si la somme de $2,785,000 est entièrement composée de dépenses et de frais périodiques ou de réclamations légitimes relatives au rendement sur l'investissement, qui s'étaleraient régulièrement sur les périodes à venir. Il se peut qu'au cours du trimestre de 1975 restant à courir à l'époque de l'ordonnance, ces prévisions s'avèrent plus élevées ou plus faibles que les dépenses véritablement engagées au cours de ce trimestre. La

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evidence of the treasurer of the Company deals with the revenues for the year 1975 as follows:

A. The revenues from gas sales for the test year 1975 of $87,265,000 as shown on line 6 of Statement 2.01 (Forecast—Proposed Rates) constitutes $84,480,000 of revenues forecast under existing rates as shown on Line 6 of Statement 2.01 (Forecast—Existing Rates) and $2,785,000 of additional revenues to earn a utility rate of return of 9.93%. The increase is that estimated to be derived from introduction on October 1, 1975, of the requested interim rates, including an increase in franchise tax of $120,000.

Q. On what year are the interim rates designed?

A. 1975 was chosen as the test year and rates were designed to recover 1975 costs.

In its application for interim rates the Company reduces the effect of the anticipated loss of revenue to the conclusion:

The rate of return on the base rate drops from 9 percent in 1974 to 8.43 percent in 1975 and further declines to 6.77 percent in 1976. The requested rate of return on rate base for 1975 under the proposed rates is 9.93 percent. This difference of 1½ percent represents $1,600,000 in utility income.

This reference would appear to be to the difference between the prevailing rates in 1975 prior to October 1st and the rates which would prevail in 1975 under the proposal made for the rates effective October 1, 1975. The application for the interim rates goes on to state:

Without rate relief in the form of interim rates for the balance of 1975, the imputed return on common equity drops to 10.2 percent compared to the recommended equity return of 14⅝ percent to 15⅛ percent . . .

From this and like excerpts from evidence, testimentary and documentary, the City has taken the view that the augmentation to rates for the last quarter of 1975 sought by the Company and granted by the Board has in effect been a recognition of a deemed increase in the rate base or operating expenses by the inclusion therein of an

preuve n'éclaire absolument pas cette question. Le trésorier de la Compagnie a présenté le témoignage suivant au sujet des revenus de l'année 1975:

[TRADUCTION] R. Les revenus de $87,265,000 provenant de la vente de gaz pour l'année témoin 1975, inscrits à la sixième ligne du relevé 2.01 (Prévisions—tarifs suggérés) comprennent $84,480,000 de revenus prévus selon les tarifs actuellement en vigueur figurant à la sixième ligne du relevé 2.01 (Prévisions—Tarifs actuels) et $2,785,000 de revenus supplémentaires destinés à permettre un taux de rendement de 9.93%. L'augmentation correspond à l'estimation du montant résultant de la demande d'augmentation provisoire des tarifs présentée le 1er octobre 1975 et à l'augmentation de $120,000 des droits sur la concession.

Q. Sur la base de quelle année les tarifs provisoires sont-ils établis?

R. L'année 1975 a été choisie comme l'année témoin et les tarifs ont été établis en fonction des coûts de cette année-là.

Dans sa demande de tarifs provisoires, la Compagnie ramène l'effet de la perte anticipée de revenus à la conclusion suivante:

[TRADUCTION] Le taux de rendement sur la base de tarification tombe de 9 pour cent en 1974 à 8.43 pour cent en 1975 et à 6.77 pour cent en 1976. Le taux de rendement pour 1975 compte tenu du tarif suggéré est de 9.93 pour cent. Cette différence de 1½ pour cent représente un revenu de $1,600,000 pour l'entreprise.

Il s'agit, semble-t-il, de la différence entre les tarifs en vigueur en 1975, jusqu'au 1er octobre, et les tarifs proposés à partir du 1er octobre 1975. La demande de tarifs provisoires dit en outre:

[TRADUCTION] Sans l'augmentation provisoire des tarifs pour le reste de l'année 1975, le rendement sur l'avoir des actionnaires ordinaires sera de 10.2 pour cent alors qu'il devrait être de 14⅝ à 15⅛ pour cent . . .

Se fondant sur cela, et sur d'autres preuves testimoniales et documentaires, la Ville prétend que l'augmentation des tarifs pour le dernier trimestre de 1975, demandée par la Compagnie et accordée par la Commission, revient à admettre une augmentation de la base de tarification ou des dépenses d'exploitation pour y inclure une perte qui ne

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otherwise unrecoverable loss in that part of the year 1975 preceding the 1975 application filed on August 20. Additionally, or perhaps more accurately, alternatively, the City has put the argument that the Company by its interim rate proposal has sought to recover in 1975 additional costs of $2.785 million without in any way establishing that the revenue so sought is required to match expenses to be incurred either during the effective period of the new interim rates, or is to recover lost revenue in the manner authorized by s. 31. In support of this argument, the City points out that the sum of $2.1 million, which is said to be required to meet increases in operating expenses, is not isolated and shown to be additional expenses to be incurred in the last quarter of 1975 but rather is the excess of 1975 expenses over and above those forecast in the earlier proceedings and which excess is forecast on the basis of actual expenditures in the first 6 months of 1975 together with anticipated expenditures in the last 6 months of 1975.

serait autrement pas remboursable pour la partie de l'année 1975 précédant le 20 août 1975, date de la présentation de la requête. En outre, ou, pour être plus précis, subsidiairement, la Ville a soutenu que l'augmentation provisoire réclamée par la Compagnie visait à compenser en 1975 un coût supplémentaire de $2,785,000 sans prouver soit que le revenu supplémentaire réclamé correspond aux dépenses engagées au cours de la période d'application des nouveaux tarifs provisoires soit qu'il vise à recouvrer une perte de revenu de la manière prévue à l'art. 31. A l'appui de cet argument, la Ville fait valoir que la somme de $2,100,000 réclamée pour faire face à l'augmentation des dépenses d'exploitation n'a été ni isolée ni identifiée comme correspondant à des dépenses supplémentaires à engager au cours du dernier trimestre de 1975. Selon la Ville, cette somme représenterait au contraire l'excédent des dépenses engagées en 1975 sur celles prévues au départ, cet excédent étant lui-même calculé en fonction de dépenses engagées durant le premier semestre de 1975 et sur les prévisions de dépenses pour le dernier semestre de cette année-là.

The Company meets this argument by the submission that losses contemplated by s. 31 cannot be discerned until the close of the fiscal period selected as the basis for the application for new rates and that this is peculiarly so in the case of a gas utility by reason of fluctuating conditions beyond the control of the utility. The Board in disposing of these opposing positions states simply:

AND THE BOARD having considered the argument of counsel for Interveners that the application for interim refundable rates by N.U.L. should be rejected, in whole or in part, on the grounds that the increased interim refundable rates are for the purpose of recovering "past losses" which they claim have been incurred by N.U.L. since January 1, 1975:

AND THE BOARD considering that the forecast revenue deficiency in the 1975 future test year requested by N.U.L. cannot be properly characterized as "past losses".

La Compagnie répond à cet argument que les pertes visées à l'art. 31 ne peuvent être identifiées avant la fin de la période d'imposition choisie pour l'application des nouveaux tarifs et ajoute que c'est particulièrement vrai dans le cas d'une entreprise de distribution de gaz, en raison de fluctuations incontrôlables. Tranchant ces thèses contradictoires, la Commission a simplement déclaré:

[TRADUCTION] ET CONSIDÉRANT l'argumentation des avocats des intervenants en faveur du rejet, en totalité ou en partie, de la requête de NUL pour l'obtention de tarifs provisoires remboursables, au motif que l'augmentation provisoire et remboursable des tarifs vise à recouvrer des «pertes passées» subies par NUL depuis le 1er janvier 1975;

ET CONSIDÉRANT que le manque à gagner prévu par NUL pour 1975, l'année témoin, ne constitue pas véritablement des «pertes passées».

The terminology "past losses", employed perhaps by all parties before the Board and adopted by the Board in its order, makes it difficult in reviewing the record as well as the various orders of the Board to determine whether or not the

L'expression «pertes passées» employée par toutes les parties ou presque devant la Commission, et reprise par cette dernière dans son ordonnance, ne facilite pas l'examen du dossier et des diverses ordonnances de la Commission lorsqu'il

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Board was indeed attempting to isolate the elements to be taken into account by the Board in discharging its functions under ss. 27, 28 and 29 of *The Gas Utilities Act* with reference to specific parts of the calendar year 1975. If, for example, the Board had assumed that the additional revenue sought in the application of September 25, 1975, for an interim order pending the determination of the application of August 20, 1975, was to match expenses forecast to be incurred by the Company in the last quarter of 1975, then there would be no attempt by the Board to take into account revenue losses incurred prior to August 20, 1975, and thus no failure on the part of the Board to comply with the statute and with s. 31 in particular. The process of matching forecast revenues to be realized from the proposed interim rates against the forecast expenses comprising the total revenue requirements for the last quarterly period would be complete. It is impossible to discern whether or not that is the result which is sought to be reflected by the Board in its order of October 1, 1975. Such may well be the case, but on the other hand, it might be as submitted by the City that these additional expenses totalling $2.785 million are in whole or in part the result of annualizing expenses incurred before and/or after August 20, 1975, so that the total revenue requirement for the "test year" need be augmented by $2.785 million in order to meet the total revenue requirements for the year. It is in my view wholly unnecessary to enter the debate as to whether or not in making the estimates for future expenses a fiscal period of a year, two years, a half year, etc., need be selected. What is required by the statute is an estimate by the Board of the future needs of the utility which are recognized in the statute to be compensable by the operation in the future of the rates prescribed by the Board. Similarly the forecast of revenues to be recovered by the proposed rates need not be predicated necessarily upon a hypothetical or real fiscal year or a shorter period. Obviously in a seasonal enterprise such as the gas utility business a full calendar fiscal period represents the marketing picture throughout the four seasons of the year. Equally obviously, recurring cash outlays relevant to expenses unevenly incurred throughout the year can be annualized

s'agit de déterminer si cette dernière a effectivement tenté d'isoler les éléments dont elle devait tenir compte pour s'acquitter de ses fonctions en vertu des art. 27, 28 et 29 de *The Gas Utilities Act*, relativement à des périodes précises de l'année civile 1975. Si, par exemple, la Commission a présumé que le revenu supplémentaire réclamé dans la requête du 25 septembre 1975, visant une ordonnance provisoire applicable en attendant que soit tranchée la requête du 20 août 1975, correspondait aux dépenses que la Compagnie prévoyait effectuer au cours du dernier trimestre de 1975, alors on peut dire que la Commission n'a pas cherché à tenir compte des pertes de revenu subies avant le 20 août 1975 et qu'elle n'a en conséquence pas violé la Loi ni, plus précisément, l'art. 31. L'objectif, qui est de faire correspondre le montant des revenus projetés provenant des tarifs provisoires proposés au montant des dépenses projetées formant le revenu total nécessaire pour le dernier trimestre, serait donc atteint. Mais il est impossible de savoir si c'est effectivement le résultat recherché par la Commission dans son ordonnance du 1er octobre 1975. Il se peut fort bien que ce soit le cas; en revanche, il se peut aussi, comme le prétend la Ville, que ces dépenses supplémentaires de $2,785,000 soient fondées, en totalité ou en partie, sur des dépenses antérieures et/ou postérieures au 20 août 1975, de sorte que le revenu total nécessaire pour «l'année témoin» doit être augmenté de $2,785,000 pour correspondre au revenu total nécessaire pour l'année. Il est à mon avis inutile de débattre la question de savoir si les estimations des dépenses à venir doivent être fondées sur l'année d'imposition, sur deux ans ou sur un semestre. La Commission est tenue d'évaluer les besoins futurs de l'entreprise dont la Loi autorise la compensation par les tarifs prescrits par la Commission pour l'avenir. Les prévisions des revenus que devront produire les tarifs proposés ne doivent pas non plus nécessairement être fondées sur une année d'imposition hypothétique ou réelle ou sur une période plus courte. Il est bien évident lorsqu'il s'agit d'une entreprise saisonnière, comme un service de distribution de gaz, qu'une année complète d'imposition donne une image fidèle des ventes de l'entreprise au cours des quatre saisons de l'année. Il est également évident que les dépen-

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either by an accounting adjustment where the expense incurred relates to a longer period or extends beyond the fiscal year in question, or can be annualized where the expense incurred relates to a segment of the fiscal period. In any case the administrative mechanics to be adopted in the discharge of the function mandated by *The Gas Utilities Act* are exclusively within the power of the Board. We need not here deal with the question of arbitrariness in the discharge of administrative functions for there is no evidence on the record before this Court raising any such issue. This Court is concerned only with the issue as to whether the Board in the performance of its duties under the statute has exceeded the power and authority given to it by the Legislature. Clement J.A. has observed in his reasons:

> [P]*rima facie* the new tentative rate base includes an amount for revenue losses in 1975 up to the date of the application in August, since the figures do not purport to apportion the loss between the two periods of the year.

I am not prepared to say that a *prima facie* case has been established that the effect of the application of the interim rates from October 1, 1975, onwards will be the recovery in the future of revenue shortfalls incurred prior to August 20, 1975. Indeed, in my respectful view, the test is not whether the "new tentative rate base includes an amount for revenue losses" but rather the question is whether or not the interim rates prospectively applied will produce an amount in excess of the estimated total revenue requirements for the same period of the utility by reason of the inclusion in the computation of those future requirements of revenue shortfalls which have occurred prior to the date of the application in question, whether or not those "shortfalls" have been somehow incorporated into the rate base or have been included in the operating expenses forecast for the period in which the new interim rates will be applied, subject always to the Board's limited power under s. 31.

The Company submitted to this Court that a determination of what is or is not a 'past loss' is a

ses de capital qui reviennent périodiquement et qui sont engagées à différentes époques de l'année peuvent être calculées sur une base annuelle avec les rectifications comptables appropriées lorsque la dépense est engagée pour une période plus longue, ou va au-delà de l'année d'imposition, ou même lorsqu'elle a trait à une partie seulement de l'année d'imposition. Quoi qu'il en soit, les techniques administratives auxquelles la Commission a recours pour s'acquitter du rôle que lui confère *The Gas Utilities Act* sont exclusivement de son ressort. Il ne saurait être question ici d'exécution arbitraire des fonctions administratives puisque le dossier soumis à cette Cour ne contient rien à cet égard. La seule question soumise à cette Cour consiste à déterminer si, dans l'exercice de ses fonctions, la Commission a excédé les pouvoirs que lui a conférés la Législature. Le juge Clement fait la remarque suivante dans ses motifs:

> [TRADUCTION] *Prima facie*, la nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu subies depuis le début de 1975 jusqu'à la date de la présentation de la requête, en août, car les calculs ne répartissent pas la perte entre les deux périodes de l'année.

Je ne suis pas prêt à dire qu'il est établi *prima facie* que l'imposition des tarifs provisoires à compter du 1er octobre 1975 permettait le recouvrement dans l'avenir de pertes de revenu subies avant le 20 août 1975. Avec égards, je suis d'avis qu'au lieu de se demander si la «nouvelle base de tarification proposée contient un montant destiné à couvrir des pertes de revenu», il faut se demander si l'imposition dans l'avenir des tarifs provisoires procurera un revenu excédant le revenu total requis selon les calculs pour la même période, suite à l'inclusion dans le calcul d'un montant destiné à couvrir les manques à gagner subis avant la date de la présentation de la requête, que ces derniers aient ou non été inclus, de quelque façon que ce soit, dans la base de tarification ou aient été inclus dans les dépenses d'exploitation prévues pour la période durant laquelle les nouveaux tarifs provisoires seront imposés, sous réserve évidemment du pouvoir limité de la Commission en vertu de l'art. 31.

La Compagnie a plaidé devant cette Cour que la détermination de ce qui constitue une «perte

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pure question of fact and as such is not subject to appeal by reason of s. 62 of *The Public Utilities Board Act, supra*, which limits appeals from Board decisions to questions of "law or jurisdiction". The appeal before this Court involves a determination of the intent of the Legislature with respect to the Board's jurisdiction to take into account shortfalls in revenue or excess expenditures occurring or properly allocable to a period of time prior to an application for the establishment of rates under the Act. The Board's decision as to the characterization of "the forecast revenue deficiency in the 1975 future test year" of the Company involves a determination of the matters of which cognizance may be taken by the Board in setting rates under the statute. This is a question of law and may properly be made the subject of an appeal to a court pursuant to s. 62. The disposition of an application which, as I have said, involved the Board in construing ss. 28 and 31 of *The Gas Utilities Act*, raises a question of law and may well go to the jurisdiction of the Board.

However, it is not possible for the reviewing tribunal in the circumstances in this proceeding to ascertain from the Board order whether the Board acted within or outside the ambit of its statutory authority. The form and content of the Board's order are so narrow in scope and of such extraordinary brevity that one is left without guidance as to the basis upon which the rates have been established for the period October 1, 1975, onwards. Hence this further submission of the Company must fail.

I turn now to the second issue, namely the application of s. 8 of *The Administrative Procedures Act* of Alberta, *supra*, to these proceedings. This provision imposes upon certain administrative tribunals the obligation of providing the parties to its proceedings with a written statement of its decision and the facts upon which the decision is based and the reasons for it. Section 8 states:

> Where an authority exercises a statutory power so as to adversely affect the rights of a party, the authority shall furnish to each party a written statement of its decision setting out
>
> (*a*) the findings of fact upon which it based its decision, and

passée» est une question de fait, non susceptible d'appel en vertu de l'art. 62 de *The Public Utilities Board Act*, précité; cet article limite l'appel des décisions de la Commission aux seules questions de «droit ou de compétence». Le présent pourvoi implique l'analyse de l'intention du législateur relativement au pouvoir de la Commission de tenir compte des manques à gagner ou des dépenses excédentaires engagées avant la présentation d'une demande de nouveaux tarifs en vertu de la Loi. La décision de la Commission au sujet du «manque à gagner prévu pour 1975, l'année témoin», comporte la détermination de questions dont la Commission prend connaissance pour fixer les tarifs en vertu de la Loi. C'est là une question de droit susceptible d'appel en vertu de l'art. 62. Une décision relative à une requête qui, comme je l'ai dit, oblige la Commission à interpréter les art. 28 et 31 de *The Gas Utilities Act*, soulève une question de droit pouvant mettre en cause la compétence de la Commission.

Cependant, les circonstances de la présente affaire ne permettent pas au tribunal qui examine l'ordonnance de la Commission d'établir si cette dernière a excédé ou non sa compétence. Le libellé et le contenu de l'ordonnance de la Commission sont en effet d'une portée si limitée et d'une telle brièveté qu'il est impossible d'établir si les tarifs ont été fixés pour la période commençant le 1er octobre 1975. Cet argument de la Compagnie ne peut donc être retenu.

J'en viens maintenant à la deuxième question en litige; elle porte sur l'application de l'art. 8 de *The Administrative Procedures Act* de l'Alberta, précitée, aux présentes procédures. Cette disposition oblige certains tribunaux administratifs à communiquer aux parties une décision écrite, exposant les conclusions de fait et les motifs sur lesquels elle est fondée. Cet article prévoit:

> [TRADUCTION] Lorsque, dans l'exercice de pouvoirs conférés par la loi, un organisme porte atteinte aux droits d'une partie, il doit communiquer à chaque partie un exposé écrit de sa décision et y préciser
>
> *a*) les conclusions de fait sur lesquelles sa décision est fondée, et

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(*b*) the reasons for the decision.

The "reasons" handed down by the Board consist of the following:

INTERIM ORDER

UPON THE APPLICATION of Northwestern Utilities Limited, (hereinafter referred to as "N.U.L.") to the Public Utilities Board for an Order or Orders approving changes in existing rates, tolls or charges for gas supplied and services rendered by N.U.L. to its customers;

AND UPON READING the application of N.U.L. dated the 20th day of August, 1975 and the Affidavit of Dorothea E. Blackwood concerning service by mail and by newspaper publication of a Notice of the matter as directed by the Board and written evidence of witnesses of N.U.L. and other material filed in support of the application;

AND UPON HEARING an application made by N.U.L. on September 25, 1975, for an Interim Order approving changes in existing rates, tolls or charges for gas supplied and services rendered by N.U.L. to its customers pending final determination of the matter;

AND UPON HEARING the application, testimony and submission of witnesses and counsel for N.U.L.;

AND THE BOARD having considered the argument of counsel for Interveners that the application for interim refundable rates by N.U.L. should be rejected, in whole or in part, on the grounds that the increased interim refundable rates are for the purpose of recovering "past losses" which they claim have been incurred by N.U.L. since January 1, 1975;

AND THE BOARD considering that the forecast revenue deficiency in the 1975 future test year requested by N.U.L. cannot be properly characterized as "past losses".

AND THE BOARD considering that delay in granting an interim increase in rates may adversely affect N.U.L.'s financial integrity and customer service;

AND N.U.L. having undertaken to refund to its customers such amounts as the Board may direct if any of the said interim rates are changed after further hearing.

IT IS ORDERED as follows: . . . .

The law reports are replete with cases affirming the desirability if not the legal obligation at common law of giving reasons for decisions (*vide Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of Ameri-*

b) les motifs de sa décision.

Voici les «motifs» exposés par la Commission:

[TRADUCTION] ORDONNANCE PROVISOIRE

THE PUBLIC UTILITIES BOARD, SUR REQUÊTE de Northwestern Utilities Limited (ci-après appelée «NUL») en vue d'obtenir une ordonnance ou des ordonnances approuvant les modifications aux tarifs, taxes ou droits actuellement perçus par NUL pour le gaz fourni et les services rendus à ses clients;

ET APRÈS LECTURE de la requête de NUL en date du 20 août 1975, de l'affidavit de Dorothea E. Blackwood relatif à la signification par courrier et la publication dans un journal d'un avis de requête, conformément aux directives de la Commission, et de la preuve écrite des témoins de NUL et autres documents produits à l'appui de la requête;

ET APRÈS AUDITION d'une requête présentée par NUL le 25 septembre 1975 en vue d'obtenir une ordonnance provisoire approuvant les modifications aux tarifs, taxes ou droits actuellement perçus par NUL pour le gaz fourni et les services rendus à ses clients, en attendant une décision définitive;

ET APRÈS AUDITION de la requête, des témoins et des avocats de NUL;

ET CONSIDÉRANT l'argumentation des avocats des intervenants en faveur du rejet, en totalité ou en partie, de la requête de NUL pour l'obtention de tarifs provisoires remboursables, au motif que l'augmentation provisoire et remboursable des tarifs vise à recouvrer des «pertes passées» subies par NUL depuis le 1er janvier 1975;

ET CONSIDÉRANT que le manque à gagner prévu par NUL pour 1975, l'année témoin, ne constitue pas véritablement des «pertes passées»;

ET CONSIDÉRANT qu'un retard à accorder une augmentation provisoire des tarifs pourrait nuire à la stabilité financière de NUL et aux services fournis aux clients;

ET CONSIDÉRANT l'engagement de NUL de rembourser à ses clients les montants prescrits par la Commission si, après audition, cette dernière décidait de modifier lesdits tarifs provisoires;

STATUE que . . .

Les recueils judiciaires regorgent de jugements affirmant qu'il est souhaitable sinon obligatoire en *common law*, de rendre des décisions motivées (voir *Gill Lumber Chipman (1973) Ltd. v. United Brotherhood of Carpenters and Joiners of Ameri-*

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ca Local 2142[7], *per* Hughes C.J.N.B. at p. 47; *MacDonald v. The Queen*[8], *per* Laskin C.J.C. at p. 262). This obligation is a salutary one. It reduces to a considerable degree the chances of arbitrary or capricious decisions, reinforces public confidence in the judgment and fairness of administrative tribunals, and affords parties to administrative proceedings an opportunity to assess the question of appeal and if taken, the opportunity in the reviewing or appellate tribunal of a full hearing which may well be denied where the basis of the decision has not been disclosed. This is not to say, however, that absent a requirement by statute or regulation a disposition by an administrative tribunal would be reviewable solely by reason of a failure to disclose its reasons for such disposition.

ca Local 2142[7], le juge en chef Hughes du Nouveau-Brunswick, à la p. 47; *MacDonald c. La Reine*[8], le juge en chef Laskin du Canada, à la p. 262). Cette obligation est salutaire: elle réduit considérablement les risques de décisions arbitraires, raffermit la confiance du public dans le jugement et l'équité des tribunaux administratifs et permet aux parties aux procédures d'évaluer la possibilité d'un appel et, le cas échéant, au tribunal siégeant en révision ou en appel d'accorder une audition complète, qui serait peut-être inaccessible si les motifs de la décision n'étaient pas révélés. Toutefois, cela ne signifie pas que la décision d'un tribunal administratif est susceptible de révision pour l'unique raison qu'elle n'est pas motivée, en l'absence d'obligation légale ou réglementaire en ce sens.

The Board in its decision allowing the interim rate increase which is challenged by the City failed to meet the requirements of s. 8 of *The Administrative Procedures Act*. It is not enough to assert, or more accurately, to recite, the fact that evidence and arguments led by the parties have been considered. That much is expected in any event. If those recitals are eliminated from the 'reasons' of the Board all that is left is the conclusion of the Board "that the forecast revenue deficiency in the 1975 future test year requested by the Company cannot be properly characterized as "past losses" ". The failure of the Board to perform its function under s. 8 included most seriously a failure to set out "the findings of fact upon which it based its decision" so that the parties and a reviewing tribunal are unable to determine whether or not, in discharging its functions, the Board has remained within or has transgressed the boundaries of its jurisdiction established by its parent statute. The obligation imposed under s. 8 of the Act is not met by the bald assertion that, as Keith J. succinctly put it in *Re Canada Metal Co. Ltd. et al. and MacFarlane*[9], at p. 587, when dealing with a similar statutory requirement, "my reasons are that I think so".

La décision de la Commission accordant l'augmentation provisoire de tarifs contestée par la Ville n'est pas conforme aux exigences de l'art. 8 de *The Administrative Procedures Act*. Il ne suffit pas d'affirmer ou, plus précisément, d'énoncer que la preuve et les moyens soumis par les parties ont été considérés. Cela va de soi. Si l'on soustrait ces attendus des «motifs» rendus par la Commission, il ne reste que la conclusion selon laquelle «le manque à gagner prévu par NUL pour 1975, l'année témoin, ne constitue pas véritablement des «pertes passées»». L'inobservation de l'art. 8 par la Commission comporte l'omission très grave d'exposer «les conclusions de fait sur lesquelles sa décision est fondée», de sorte qu'il est impossible pour les parties et pour le tribunal siégeant en révision de déterminer si, dans l'exercice de ses fonctions, la Commission a respecté ou excédé les limites de sa compétence qu'établit sa loi organique. L'exigence prévue à l'art. 8 de la Loi n'est pas respectée si l'on se contente de dire, comme le mentionne le juge Keith dans *Re Canada Metal Co. Ltd. et al. and MacFarlane*[9], à la p. 587, à propos d'un cas semblable, [TRADUCTION] «mes motifs sont que telle est ma conclusion».

[7] (1973), 7 N.B.R. (2d) 41 (N.B.S.C.A.D.).
[8] (1976), 29 C.C.C. (2d) 257.
[9] (1973), 1 O.R. (2d) 577.

[7] (1973), 7 N.B.R. (2d) 41 (N.B.S.C.A.D.)
[8] (1976), 29 C.C.C. (2d) 257.
[9] (1973), 1 O.R. (2d) 577.

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The appellants are not assisted by the decision of the Appellate Division of the Supreme Court of Alberta in *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.*[10], affirmed by this Court at [1977] 2 S.C.R. 822 to the effect that under s. 8 of *The Administrative Procedures Act* the reasons must be proper, adequate and intelligible, and must enable the person concerned to assess whether he has grounds of appeal. Nor can the Board rely on the peculiar nature of the order in this case, being an interim order with the amounts payable thereunder perhaps being refundable at some later date, to deny the obligation to give reasons. Brevity in this era of prolixity is commendable and might well be rewarded by a different result herein but for the fact that the order of the Board reveals only conclusions without any hint of the reasoning process which led thereto. For example, none of the factors which the Board took into account, in reaching its conclusion that the amounts contested were not "past losses" are revealed so that a reviewing tribunal cannot with any assurance determine that the statutory mandates bearing upon the Board's process have been heeded.

Les appelantes ne trouvent aucun appui dans l'arrêt de la Division d'appel de la Cour suprême de l'Alberta *Dome Petroleum Ltd. v. Public Utilities Board (Alberta) and Canadian Superior Oil Ltd.*[10], confirmé par cette Cour à [1977] 2 R.C.S. 822, où il fut jugé que pour être conformes à l'art. 8 de *The Administrative Procedures Act*, les motifs doivent être appropriés, pertinents et intelligibles, et doivent permettre à la partie concernée d'évaluer les possibilités d'appel. La Commission ne peut pas invoquer non plus le caractère particulier de l'ordonnance en question, savoir une ordonnance provisoire dont les dispositions prévoient la possibilité d'un remboursement des montants perçus sous son autorité, pour se soustraire à son obligation de rendre une décision motivée. A une époque où le style est souvent verbeux, la brièveté est un atout et elle aurait pu donner lieu à un résultat différent en l'espèce si ce n'était que l'ordonnance de la Commission ne comporte que des conclusions et est muette quant au raisonnement suivi pour y arriver. Par exemple, la Commission ne révèle aucun des facteurs pris en considération pour parvenir à la conclusion que le montant contesté ne constitue pas des «pertes passées», de sorte que le tribunal siégeant en révision ne peut établir avec certitude si la Commission a observé les exigences légales dans l'élaboration de sa décision.

The Appellate Division of the Supreme Court of Alberta, after coming to the same result, vacated the Board's order and referred the matter to the Board for further consideration and determination pursuant to s. 64 of *The Public Utilities Board Act*. In doing so, it is evident from the reasons for judgment of the said Court that the Court properly viewed its appellate jurisdiction under s. 64 of *The Public Utilities Board Act* as a limited one. It is not for a court to usurp the statutory responsibilities entrusted to the Board, except in so far as judicial review is expressly allowed under the Act. It is, of course, otherwise where the administrative tribunal oversteps its statutory authority or fails to perform its functions as directed by the statute. Questions as to how and when operating expenses are to be measured and recovered through pre-

[10] (1976), 2 A.R. 453.

Parvenue à la même conclusion, la Division d'appel de la Cour suprême de l'Alberta a annulé la décision de la Commission et lui a renvoyé le dossier pour qu'elle l'examine à nouveau et rende une décision conformément à l'art. 64 de *The Public Utilities Board Act*. Il est évident, à la lecture des motifs de jugement de ladite cour, qu'elle a à juste titre considéré que sa compétence en appel aux termes de l'art. 64 de cette loi était limitée. Une cour ne doit pas s'approprier les responsabilités administratives conférées à la Commission, sauf dans la mesure où l'examen judiciaire est expressément prévu par la Loi. Bien sûr, il en va autrement lorsque le tribunal administratif excède ses pouvoirs ou n'exerce pas ses fonctions conformément à la Loi. Sous réserve des limites imposées par la Loi, il appartient à la Commission

[10] (1976), 2 A.R. 453.

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scribed rates are, subject to the limits imposed by the Act itself, for the Board to decide, and the procedures for such decisions if made within the confines of the statute are administrative matters which are better left to the Board to determine (*vide City of Edmonton v. Northwestern Utilities Limited, supra, per* Locke J. at p. 406).

As for the participation of The Public Utilities Board in these proceedings, it was pointed out to the Court that s. 65 of *The Public Utilities Board Act* entitles the Board "to be heard . . . upon the argument of any appeal". Under s. 66 of the Act the Board is shielded from any liability in respect of costs by reason or in respect of an appeal.

Section 65 no doubt confers upon the Board the right to participate on appeals from its decisions, but in the absence of a clear expression of intention on the part of the Legislature, this right is a limited one. The Board is given *locus standi* as a participant in the nature of an *amicus curiae* but not as a party. That this is so is made evident by s. 63(2) of *The Public Utilities Board Act* which reads as follows:

> The party appealing shall, within ten days after the appeal has been set down, give to the parties affected by the appeal or the respective solicitors by whom the parties were represented before the Board, and to the secretary of the Board, notice in writing that the case has been set down to be heard in appeal, and the appeal shall be heard by the court of appeal as speedily as practicable.

Under s. 63(2) a distinction is drawn between "parties" who seek to appeal a decision of the Board or were represented before the Board, and the Board itself. The Board has a limited status before the Court, and may not be considered as a party, in the full sense of that term, to an appeal from its own decisions. In my view, this limitation is entirely proper. This limitation was no doubt consciously imposed by the Legislature in order to avoid placing an unfair burden on an appellant who, in the nature of things, must on another day and in another cause again submit itself to the rate fixing activities of the Board. It also recognizes the

de déterminer comment calculer les dépenses d'exploitation et leur recouvrement par l'imposition de tarifs appropriés et la procédure suivie pour parvenir à cette décision, si cette dernière est rendue dans le cadre de la Loi, constitue une question administrative dont la Commission est le meilleur juge (voir *Ville d'Edmonton c. Northwestern Utilities Limited*, précité, le juge Locke, à la p. 406).

En ce qui concerne la participation de The Public Utilities Board aux présentes procédures, on a cité à la Cour l'art. 65 de *The Public Utilities Board Act* selon lequel la Commission a le droit [TRADUCTION] «d'être entendue . . . et de faire valoir ses arguments sur tout appel». L'article 66 de la Loi dégage la Commission de toute responsabilité quant aux dépens de l'appel.

Il est évident que l'art. 65 confère à la Commission le droit de participer à l'appel de ses décisions, mais en l'absence d'indication précise de l'intention du législateur, ce droit est limité. La Commission a un *locus standi* et son droit de participer aux procédures d'appel s'apparente à celui d'un *amicus curiae* et non à celui d'une partie. Cela ressort clairement du par. 63(2) de *The Public Utilities Board Act* que voici:

> [TRADUCTION] La partie qui interjette appel doit, dans les dix jours de l'inscription de l'appel, donner aux parties touchées par l'appel ou à leurs procureurs respectifs devant la Commission, et au secrétaire de la Commission, un avis écrit de l'inscription de l'appel pour audition et la cour d'appel doit entendre l'appel dans les plus brefs délais.

Le paragraphe 63(2) fait une distinction entre les «parties» qui interjettent appel de la décision de la Commission ou qui étaient représentées devant la Commission, et la Commission elle-même. La Commission a un rôle limité devant la Cour et elle ne peut pas être considérée comme une partie, au sens plein du terme, dans les procédures d'appel de ses propres décisions. J'estime cette restriction tout à fait justifiée. Le législateur l'a sans aucun doute consciemment imposée dans le but d'éviter de mettre un fardeau injuste sur les épaules d'un appelant qui, par la nature des choses, devra éventuellement retourner devant la Commission et se

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universal human frailties which are revealed when persons or organizations are placed in such adversarial positions.

This appeal involves an adjudication of the Board's decision on two grounds both of which involve the legality of administrative action. One of the two appellants is the Board itself, which through counsel presented detailed and elaborate arguments in support of its decision in favour of the Company. Such active and even aggressive participation can have no other effect than to discredit the impartiality of an administrative tribunal either in the case where the matter is referred back to it, or in future proceedings involving similar interests and issues or the same parties. The Board is given a clear opportunity to make its point in its reasons for its decision, and it abuses one's notion of propriety to countenance its participation as a full-fledged litigant in this Court, in complete adversarial confrontation with one of the principals in the contest before the Board itself in the first instance.

It has been the policy in this Court to limit the role of an administrative tribunal whose decision is at issue before the Court, even where the right to appear is given by statute, to an explanatory role with reference to the record before the Board and to the making of representations relating to jurisdiction. (*Vide The Labour Relations Board of the Province of New Brunswick v. Eastern Bakeries Limited et al.*[11]; *The Labour Relations Board of Saskatchewan v. Dominion Fire Brick and Clay Products Limited et al.*[12]) Where the right to appear and present arguments is granted, an administrative tribunal would be well advised to adhere to the principles enunciated by Aylesworth J.A. in *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board*[13], at pp. 589, 590:

[11] [1961] S.C.R. 72.
[12] [1947] S.C.R. 336.
[13] (1958), 18 D.L.R. (2d) 588.

soumettre de nouveau à ses procédures de détermination des tarifs. Cette restriction offre également une protection contre les défaillances humaines qui entrent en jeu lorsque des personnes ou des organismes se retrouvent ainsi en situation de conflit.

Aux fins de ce pourvoi, l'analyse de la décision de la Commission doit se fonder sur deux considérations concernant l'une et l'autre la légalité d'un acte administratif. L'une des deux appelantes est la Commission elle-même; son avocat a présenté une argumentation détaillée et approfondie à l'appui de la décision de la Commission en faveur de la Compagnie. Une participation aussi active ne peut que jeter le discrédit sur l'impartialité d'un tribunal administratif lorsque l'affaire lui est renvoyée ou lorsqu'il est saisi d'autres procédures concernant des intérêts et des questions semblables ou impliquant les mêmes parties. La Commission a tout le loisir de s'expliquer dans ses motifs de jugement et elle a enfreint de façon inacceptable la réserve dont elle aurait dû faire preuve lorsqu'elle a participé aux procédures comme partie à part entière, en opposition directe à une partie au litige dont elle avait eu à connaître en première instance.

Cette Cour, à cet égard, a toujours voulu limiter le rôle du tribunal administratif dont la décision est contestée à la présentation d'explications sur le dossier dont il était saisi et d'observations sur la question de sa compétence, même lorsque la loi lui confère le droit de comparaître. (Voir les arrêts *The Labour Relations Board of the Province of New Brunswick c. Eastern Bakeries Limited et autres*[11]; *The Labour Relations Board of Saskatchewan c. Dominion Fire Brick and Clay Products Limited et autres*[12].) Lorsque la loi donne à un tribunal administratif le droit de comparaître et de plaider, ce dernier aurait tout avantage à suivre les principes énoncés par le juge Aylesworth dans l'arrêt *International Association of Machinists v. Genaire Ltd. and Ontario Labour Relations Board*[13], aux pp. 589 et 590:

[11] [1961] R.C.S. 72.
[12] [1947] R.C.S. 336.
[13] (1958), 18 D.L.R. (2d) 588.

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Clearly upon an appeal from the Board, counsel may appear on behalf of the Board and may present argument to the appellate tribunal. We think in all propriety, however, such argument should be addressed not to the merits of the case as between the parties appearing before the Board, but rather to the jurisdiction or lack of jurisdiction of the Board. If argument by counsel for the Board is directed to such matters as we have indicated, the impartiality of the Board will be the better emphasized and its dignity and authority the better preserved, while at the same time the appellate tribunal will have the advantage of any submissions as to jurisdiction which counsel for the Board may see fit to advance.

Where the parent or authorizing statute is silent as to the role or status of the tribunal in appeal or review proceedings, this Court has confined the tribunal strictly to the issue of its jurisdiction to make the order in question. (*Vide Central Broadcasting Company Ltd. v. Canada Labour Relations Board and International Brotherhood of Electrical Workers, Local Union No. 529*[14].)

In the sense the term has been employed by me here, "jurisdiction" does not include the transgression of the authority of a tribunal by its failure to adhere to the rules of natural justice. In such an issue, when it is joined by a party to proceedings before that tribunal in a review process, it is the tribunal which finds itself under examination. To allow an administrative board the opportunity to justify its action and indeed to vindicate itself would produce a spectacle not ordinarily contemplated in our judicial traditions. In *Canada Labour Relations Board v. Transair Ltd. et al.*[15], Spence J. speaking on this point, stated at pp. 746-7:

It is true that the finding that an administrative tribunal has not acted in accord with the principles of natural justice has been used frequently to determine that the Board has declined to exercise its jurisdiction and therefore has had no jurisdiction to make the decision which it has purported to make. I am of the opinion, however, that this is a mere matter of technique in determining the jurisdiction of the Court to exercise the remedy of *certiorari* and is not a matter of the tribunal's defence of its jurisdiction. The issue of whether or not a board has

[14] [1977] 2 S.C.R. 112.
[15] [1977] 1 S.C.R. 722.

[TRADUCTION] Il ne fait aucun doute qu'en appel d'une décision du Conseil, celui-ci peut se faire représenter par un avocat qui plaidera sa cause devant le tribunal d'appel. Nous estimons toutefois approprié que la plaidoirie traite non du fond de l'affaire entre les parties qui ont comparu devant le Conseil, mais plutôt de la compétence ou du défaut de compétence de ce dernier. Si l'avocat du Conseil mène sa plaidoirie de la sorte, l'impartialité du Conseil sera d'autant mieux mise en valeur et sa dignité et son autorité en seront d'autant mieux garanties. En même temps, le tribunal d'appel bénéficiera de toutes les observations que l'avocat du Conseil jugera utiles de présenter sur la question de compétence.

Lorsque la loi constitutive ou organique ne dit rien du rôle ni du statut du tribunal dans les procédures d'appel ou d'examen judiciaire, cette Cour a limité ledit rôle à la seule question de la compétence pour rendre l'ordonnance contestée. (Voir *Central Broadcasting Company Ltd. c. Le Conseil canadien des relations du travail et la Fraternité internationale des ouvriers en électricité, Section locale nº 529*[14].)

Au sens où j'ai employé ce mot ici, la «compétence» n'inclut pas la transgression du pouvoir d'un tribunal par l'inobservation des règles de justice naturelle. Dans un tel cas, lorsqu'une partie aux procédures devant ce tribunal est également partie aux procédures de révision, c'est le tribunal lui-même qui fait l'objet de l'examen. Accorder au tribunal administratif la possibilité de défendre sa conduite et en fait de se justifier donnerait lieu à un spectacle auquel nos traditions judiciaires ne nous ont pas habitués. Dans l'arrêt *Re Conseil canadien des relations du travail c. Transair Ltd. et autres*[15], le juge Spence a écrit à ce sujet (pp. 746-7):

Il est exact qu'on a souvent utilisé la conclusion selon laquelle un tribunal administratif a manqué aux principes de justice naturelle pour décider qu'il a renoncé à l'exercice de sa compétence et par conséquent qu'il se trouvait dans l'impossibilité de statuer, comme il prétendait le faire. Cependant, j'estime que c'est là simplement une façon de permettre à la Cour d'avoir recours au *certiorari* et non une question qui touche à la compétence que le tribunal prétend avoir. Il est évident qu'il n'appartient pas au Conseil qui voit sa façon d'exercer

[14] [1977] 2 R.C.S. 112.
[15] [1977] 1 R.C.S. 722.

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acted in accordance with the principles of natural justice is surely not a matter upon which the Board, whose exercise of its functions is under attack, should debate, in appeal, as a protagonist and that issue should be fought out before the appellate or reviewing Court by the parties and not by the tribunal whose actions are under review.

There are other issues subordinate to the two principal submissions which I have discussed above but which are inappropriate for comment at this stage by reason of the disposition which I propose in respect to this appeal. I would dismiss the appeal with costs to the respondent The City of Edmonton as against the appellant Northwestern Utilities Limited. In the result, therefore, the matter would revert to the Board for a continuation of the processing of the application by the Company of August 20, 1975, involving, as discussed above, the ascertainment by any means appropriate to the provisions of the statute, the expenses estimated to be incurred in the future and to be therefore properly recoverable by the application of the rates to be established by the Board; and in the event that s. 31 be invoked for the ascertainment of only those expenses which had been incurred after the application of August 20, 1975. Any further analysis of the factual background and subordinate issues would, in view of this disposition, be inappropriate.

Appeal dismissed with costs.

Solicitors for the appellant, The Public Utilities Board for the Province of Alberta: Major, Caron & Co., Calgary.

Solicitors for the appellant, Northwestern Utilities Ltd.: Milner & Steer, Edmonton.

Solicitor for the respondent, The City of Edmonton: M. H. Patterson, Calgary.

ses fonctions contestée, de plaider en appel, à titre d'intéressé, sur la question de savoir s'il a ou non agi conformément aux principes de justice naturelle; c'est là un point dont doivent débattre en appel les parties et non le tribunal dont les actions sont soumises à examen.

Il existe des questions sous-jacentes à ces deux points principaux mais, étant donné ma conclusion dans ce pourvoi, il est inutile d'en discuter ici. Je suis d'avis de rejeter le pourvoi, avec dépens en faveur de la ville d'Edmonton et à l'encontre de l'appelante Northwestern Utilities Limited. Je suis donc d'avis de renvoyer le dossier devant la Commission afin qu'elle poursuive l'étude de la requête présentée par la Compagnie le 20 août 1975 et qu'elle évalue, conformément à la Loi, les dépenses à venir et en ordonne le recouvrement par les tarifs qu'elle fixera; et, dans l'éventualité où l'on invoquerait l'art. 31, afin qu'elle évalue les seules dépenses engagées après la requête du 20 août 1975. Etant donné ma conclusion, une analyse plus poussée des faits et des autres questions sous-jacentes n'est pas pertinente.

Pourvoi rejeté avec dépens.

Procureurs de l'appelante, The Public Utilities Board de la Province de l'Alberta: Major, Caron & Co., Calgary.

Procureurs de l'appelante: Northwestern Utilities Ltd.: Milner & Steer, Edmonton.

Procureur de l'intimée, La ville d'Edmonton: M. H. Patterson, Calgary.

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CITY OF CALGARY AND HOME OIL CO. LTD. v. MADISON NATURAL GAS CO. LTD. AND BRITISH AMERICAN UTILITIES LTD.

Alberta Supreme Court, Appellate Division, Clinton J. Ford C.J.A. and Egbert J. and Boyd McBride, Porter and Johnson JJ.A. April 29, 1959.

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S. J. Helman, Q.C., and *R. R. Neeve*, for Calgary (City), appellant; *J. R. McColough*, for Home Oil Co., appellant by order; *J. V. H. Milvain*, Q.C., and *J. H. Laycroft*, for Madison Natural Gas Co., respondent; *R. L. Fenerty*, Q.C., for Br. American Utilities Ltd., respondent.

CLINTON J. FORD C.J.A.:—I concur in the judgment of my brother H. G. Johnson, and in his reasons. I add a few words merely to guard against any inference that we have been concerned in this appeal with what the Board of Public Utility Commissioners may take into consideration in arriving at or fixing prices to be paid for gas on an application to it for such purpose.

The question before us has been that of the authority or jurisdiction of the Board to deal with cls. (a) and (b) of the application in the sense in which they must be interpreted, rather than that of the elements or factors that enter into the problem of fixing prices. We have held that the Board has no power to entertain these portions of the application for the reasons given in our judgment.

The decision of this Division in *Wainwright Gas Co.* v. *Wainwright & Bd. Public Utility Com'rs*, [1930] 4 D.L.R., 1000, 25 A.L.R. 181; affd [1931] 4 D.L.R. 80, dealt entirely with whether there was a question of law or jurisdiction involved so as to give a right of appeal from the decision of the Board in respect of the prices it had fixed for gas on the ground that it had exceeded its jurisdiction. The majority held that there had been no violation of any legal provision. An attempted appeal by the Gas company to the Supreme Court of Canada was quashed for want of jurisdiction in that Court to hear the appeal.

It is quite clear that the *Wainwright* decision as well as the decision in *Northwestern Utilities Ltd.* v. *Edmonton*, [1929], 2 D.L.R. 4, S.C.R. 186 referred to therein, were both dealing with the question of what may be considered in the fixing of prices, as

to which, as I have said, we have not been concerned in this appeal.

EGBERT J. and BOYD MCBRIDE J.A. concur with JOHNSON J.A.

PORTER J.A.:—The scheme of the Act, [*Public Utilities Act*, R.S.A. 1955, c. 267], and the powers given to the Board, require it to fix the price of gas at the well-head, to fix the buying and selling price at each step of the process of making the gas merchantable, so that the spread between the buying price and the selling price will yield to the operators a gain that will make a return that is just and reasonable, having regard to the fact that the operators are declared to be and intended to function as public utilities. As a condition precedent to its ability to determine a just and reasonable rate, the Board of necessity had to determine the amount of capital employed in giving services by each of the respondent companies, and then to decide what rate of return upon the capital so found is proper. It will thus be seen that the just and reasonable price which the Board is to fix for the commodity in its different stages of treatment is the product of a number of things, no one of which by itself could effect the purpose of the Act.

What has been said with respect to the nature of the Board's duties under the statute affects as well the city's application to fix the future rate of return, as set out in cl. (b) thereof. In order to alter the rate of return the Board would have to reconsider the just and reasonable price to be paid to the respondents for the gas they handled. It seems apparent therefore, that the Board could not deal with the rate of return separately as requested by the city, but would be bound in dealing with the rate of return to resort to the process directed by the Act for fixing just and reasonable prices for the gas in its several states of treatment.

The City of Calgary and the Home Oil Co. contended that O. 41 of the Board was validated by a provision of the Act repealing the *Natural Gas Utilities Act*, 1944 (Alta.), c. 4, and therefore the Board had statutory authority to dispose of the earned surpluses under the provisions contained in that order, in terms as follows: "(3) (d) At any period when Madison's operations are under review, any excess or deficiency of earnings over or under the prescribed rate of return shall be dealt with and disposed of as the Board may direct." For this the city and the Home Oil Co. relied on s. 2 of 1949 (Alta. 2nd Sess.), c. 4, reading as follows: "Notwithstanding the repeal of this Act, all orders made by the Board shall be valid and remain in full force and effect until they are annulled or expire."

Whether the provisions of (3)(d) are within the Board's powers need not here be decided because they do not relieve the Board

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from the duty of following the methods directed by the statute in altering or fixing prices and rates.

In my opinion therefore the Board is without jurisdiction to hear the city's application to dispose of the surpluses earned by the respondents over the rate of return by causing them to be disgorged or paid out, and the Board cannot under its powers fix a future rate of return for the respondents as requested by the city's application cl. (b) without reconsidering a just and reasonable price to be paid by and to the respondents for the gas received in and delivered out of their plants, involving of course a consideration of all the elements that properly make a rate base and fix the rate of return. What elements the Board may take into consideration in carrying out its statutory duties is a question which is not before us on the issues raised in this appeal.

It follows that the decision of this Division in *Wainwright Gas Co.* v. *Wainwright & Bd. Public Utility Com'rs*, [1930] 4 D.L.R. 1000, 25 A.L.R. 181; affd [1931] 4 D.L.R. 80, which was much relied on in argument, has no application to the matters here involved. It may be that at another time and on different facts, the real meaning of that decision will fall to be considered by this Division. I would prefer to reserve until that time, a consideration of such questions as then may appropriately arise.

JOHNSON J.A.:—This is an appeal, by leave, from the decision of the Board of Public Utility Commissioners which dismissed in part an application by the City of Calgary. This application as amended asked for an order or orders fixing and determining:

"(a) The disposition of surpluses earned by Madison Natural Gas Co. Ltd. and/or British American Utilities Ltd. over the rate of return allowed the said utilities by the said Board;

"(b) The future rate of return to be allowed the said Madison Natural Gas Co. Ltd. and/or the said British American Utilities Ltd."

(c), (d) and (e) asked for decreases in the price of gas charged by the respondents but that part of the application is not before us.

When the application was made with respect to (a) and (b), objection was taken that the Board had no authority to entertain the application or grant the orders asked for. The Board gave effect to this objection and it is that decision which is the subject-matter of this appeal.

To understand the problem that is raised by this appeal, it is necessary to refer to the problem these orders dealt with, some of the decisions and orders made by the Natural Gas Utility Board and the legislation under which they were made. The following is taken from O. 34 of the Natural Gas Utilities Board issued in 1947:

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"Turner Valley Oil and Gas Field is situate approximately thirty miles south-west from the City of Calgary. Drilling for oil began in this field in the year 1914 but it was not until 1924 that Royalite Oil Company Limited brought in a well . . . known as Royalite No. 4, which had an initial gas flow of approximately 22,000,000 cubic feet per day. The gas produced was saturated with naphtha and as a result development followed rapidly and many wells were drilled, to secure the naphtha production. In the meantime, The Canadian Western Natural Gas, Light, Heat and Power Company Limited, which furnished natural gas to consumers through a distribution system which extended from Calgary to Lethbridge and thence to communities on the Crows Nest Line of the Canadian Pacific Railway Company, required additional supplies for its market and negotiated an agreement with Royalite, whereby the latter secured the exclusive right to supply natural gas from Turner Valley to Canadian Western for the needs of its customers.

"In course of time, crude oil was discovered in the westerly part of the field and again intensive development took place, until a time came when the limits of the field became reasonably well defined. The known productive area of Turner Valley is about twenty miles long and varies in width from one to two miles. It is divided longitudinally into two areas known respectively as 'the gas cap' on the east flank and 'the crude oil zone' on the west flank, the former of which produces natural gas containing natural gasoline and naphtha, while the latter zone produces crude oil under the lifting power of connate natural gas, which also contains natural gasoline. The northern area of the gas cap formerly was largely and now is controlled by Royalite which, in course of time, constructed two absorption plants for the recovery of natural gasoline. The natural gas in both areas of the field contains sulphuretted hydrogen in noxious quantities and a scrubbing plant was built for the removal of this dangerous substance. In the central portion of the field, Gas and Oil Products Limited established an absorption plant for the recovery of natural gasoline.

"British American Oil Company Limited established an absorption plant in the southern portion of the field for the recovery of natural gasoline. The result was that natural gas was being produced from the gas cap in tremendous quantities, primarily for the recovery of its naphtha and natural gasoline content, while natural gas — the lifting power — was produced in the crude oil zone. In the case of Gas and Oil Products Limited and the British American Oil Company Limited, gas from which natural gasoline had been recovered was used in relatively small quantities for field purposes and the balance was burned in flares. Royalite used its gas after absorption, to some extent, for use in the field for drilling

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fuel, for plant fuel, and for sale to Canadian Western to the extent of the latter's demand, and some was stored in the Bow Island field. Up until 1938 the balance was flared. . . . In the crude oil zone, gas produced from wells not connected to absorption plants and not required for field purposes or drilling fuel was wasted. Between the year 1924 and the present time literally billions of cubic feet of natural gas were wasted either by being burned in flares or by being dissipated in the air."

"This Board was then constituted under and its powers defined by The Natural Gas Utilities Act. Pipe lines, scrubbing plants, wells, systems, plant and equipment, for the production of natural gas were declared to be public utilities. Any exclusive feature in a contract such as that contained in the agreement between Royalite and Canadian Western was declared to be null and void and the Board was given wide powers respecting the sale of natural gas, the prices to be paid to producers, the production from wells, the return to the underground formation of gas not required for the market, and the retention of natural gas in the ground by the restriction of production."

Among the very wide powers given to the Board, was the power to fix and determine (again quoting from O. 34):

"(a) the just and reasonable price to be paid to producers for natural gas, . . .

"(b) the just and reasonable price for gas which has been delivered to an absorption plant . . .

"(c) the just and reasonable price for gas after it has been purified, . . .

"(d) the just and reasonable price to be paid for gas which is returned to the underground formation;

"(e) a price to be paid for gas retained in the underground formation;

"(f) the proportions in which the proceeds from the sale of absorption plant products shall be divided between producers and the owners of absorption plants."

The respondent British American Gas Utilities Ltd. is a subsidiary of British American Oil Co., and the respondent Madison Natural Gas Co., is a wholly-owned subsidiary of Royalite.

The purpose of the Act, as understood by the Board, was "to effect conservation of natural gas and to secure to producers, as far as it is possible to do so, a share in any market which can utilize natural gas" (O. 34). The Board commenced the hearing in 1945 and rendered its decision in 1947. Several interim orders were made while the hearings were in progress. Order 41 which implements

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the Board's decision (O. 34) was issued January 28, 1948. In its decision the Board considered that the rate of return should be 7% per annum and fixed 9c per mcf. as the "just and reasonable price" to be paid to the respondents. In arriving at this figure of 9c the Board had no previous experience to guide it. By experience I mean years of previous operation under controlled prices. In fixing its rates, the Board acted upon evidence of experts and the limited information which was obtained while the interim orders were in effect. In their decision (O. 34) they said: "A price of Nine (9) cents will afford what the Board hopes to be a margin of safety so that a deficit for the period will be avoided and if it should turn out that there is a surplus, it can be dealt with when the time arrives."

Order 41, which I have said implements their decision, contained the following: "(3)(d) At any period when Madison's operations are under review, any excess or deficiency of earnings over or under the prescribed rate of return shall be dealt with and disposed of as the Board may direct." A similar provision deals with British American Utilities.

It is the contention of the appellants that both respondents have received monies in excess of the rate of return fixed by the Board and its application is to dispose of these surpluses. While the respondents do not admit that they have received such surpluses, the appeal has been argued on the basis that a surplus exists.

There was discussion before us as to what was meant by "shall be dealt with and disposed of" in the portion of O. 41 which I have quoted. Does it mean that these companies shall be required to pay out or "disgorge" monies received in excess of the rate of return, or does it contemplate an application of these monies within the company so as to reduce the rate base or otherwise affect the future earning of the company? As will be pointed out later, the latter disposition is not before us, so it can only be a disposition which would require these respondents to disgorge these excess monies that will be considered.

In my opinion, the decision of the Board under appeal is correct for the reasons set forth therein. The Board has held that it has no jurisdiction to deal with or dispose of this surplus.

The powers of the Natural Gas Utilities Board have been quoted above and the Board's function was to determine "the just and reasonable price" or prices to be paid. It was to deal with rates prospectively and having done so, so far as that particular application is concerned, it ceased to have any further control. To give the Board retrospective control would require clear language and there is here a complete absence of any intention to so empower the Board.

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It is argued that O. 41 has not been appealed and that by s. 44(8) of the *Natural Gas Utilities Act,* 1944 (Alta.), c. 4, every decision of the Board not appealed is final and may not "be questioned or reviewed, restrained or removed by prohibition, injunction, *certiorari* or any other process or proceeding in any Court". If it is sought to enforce orders which are beyond the power given by the Legislature, it is settled law that Courts can declare such orders bad, notwithstanding provisions such as are contained in s. 44(8).

It was submitted that the respondents, having for over 10 years accepted money under the terms of O. 41, one of which was that the Board was reserving the right to deal with and dispose of any surplus earned above the rate of return set by the Board, they cannot now be heard to say that it is invalid. This can only be so if these facts establish estoppel. The essential elements to create estoppel are missing, and, in any case, a decision, invalid for lack of jurisdiction, cannot be a foundation for estoppel: *Toronto R. Co.* v. *Toronto,* [1904] A.C. 809 at p. 815.

Section 35*a* [enacted 1945 (Alta.), c. 31, s. 2] of the *Natural Gas Utilities Act* provided:

"35*a*(1) In addition to, and without limiting or restricting any other powers or jurisdiction conferred on it by the provisions of this Act, in any case where notice has been given by the Board of any hearing or investigation (in this section referred to as 'the final hearing') to be held or conducted by it for the determination or fixing of rates, prices, charges or any other matter or thing within its jurisdiction, the Board, —

"(*a*) if it be of the opinion that the public interest or the interest of any proprietor or of any person affected by the operations of a public utility so requires; and

"(*b*) after notice to, and hearing any oral or written representations that may be made by any person interested in or to be affected thereby, —

may make such interim or temporary order or orders relative to the matters with respect to which notice of a final hearing has been given, as it may deem just and reasonable, to be effective until the determination of the final hearing and the making of the Board's decision or order giving effect thereto (in this section referred to as 'the final order').

"(3) The Board is hereby authorized, empowered and directed, on the final hearing, to give consideration to the effect of the operation of such interim or temporary order and in the final order to make, allow or provide for such adjustments, allowances or other factors, as to the Board may seem just and reasonable."

It is the submission of the appellants that O. 34 and O. 41 are

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interim or temporary orders and the Board can now deal with these surpluses in accordance with s-s (3). As I have mentioned, orders fixing interim prices were made while the Board was hearing the application and considering its report. These, of course, were superseded by the order now under consideration. Orders 34 and 41 are, of course, not final orders in the sense that judgments are final. The Act contemplates that subsequent applications will be made to change the price fixed by these orders. They are nonetheless final so far as each application is concerned.

In 1949 (Alta. 2nd Sess.), c. 4, s. 2, the *Natural Gas Utilities Act* was repealed, and the functions previously exercised by the Board under that Act were distributed between the Public Utilities Board and the Conservation Board created by the *Oil and Gas Resources Conservation Act* [now R.S.A. 1955, c. 227]. Section 2 of this repealing Act provided: "Notwithstanding the repeal of this Act all orders made by the Board shall be valid and remain in full force and effect until they are annulled or expire, or until others are made in their stead by the Board of Public Utility Commissioners or by The Petroleum and Natural Gas Conservation Board." It is the argument of the appellants that by this section, the Legislature intended to validate all orders of the Board including orders which went beyond the jurisdiction of the Board to make. Great stress was placed on the words "shall be valid". It is argued that these words would be surplusage unless such an interpretation was placed upon them. There are other expressions in the section which to me indicate a contrary intention. "Notwithstanding the repeal of this Act" appears to limit the orders which are validated to those orders which, upon the repeal of the Act, would otherwise become invalid. The words "remain in full force and effect" certainly could not apply to an order or a portion of an order which was invalid at the date of repeal and which could not be said to have "force and effect" at that time.

In *Minister of Health* v. *The King,* [1931] A.C. 494, the House of Lords was considering a provision in the *Housing Act* of 1925 which gave the Minister power to confirm by order an improvement scheme made under the Act, and the Act went on to provide that "the order of the Minister when made shall have effect as if enacted in this Act". The scheme submitted to the Minister was inconsistent with the provisions of the Act, and the effect of the order of the Minister which confirmed the scheme, with modifications, had to be considered. Viscount Dunedin at pp. 501-2 says: "It is evident that it is inconceivable that the protection should extend without limit. If the Minister went out of his province altogether, if, for example, he proposed to confirm a scheme which said that all the proprietors in a scheduled area should make a per

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capita contribution of 5*l.* to the municipal authority to be applied by them for the building of a hall, it is repugnant to common sense that the order would be protected, although, if there were an Act of Parliament to that effect, it could not be touched." Lord Tomlin at p. 520: "The Minister's jurisdiction to make an order is under the Act strictly conditioned, and it is only when what is done falls within the limits of the conditions imposed that the order receives the force conferred by the sub-section in question."

Although the legislation here considered is retrospective in that it confirms orders already made, it is equally inconceivable that the Legislature would be giving vitality to orders or parts of orders which were invalid before the repealing Act was passed.

If the Legislature had intended specifically to validate orders that were of questionable validity, one would have expected that it would have followed the usual procedure of naming the orders in the Act.

The portion of O. 41 which is in question is severable from the other portions of the order and a declaration that it was beyond the power of the Board which made it will not otherwise affect O. 41.

There remains that portion of the motion which asks the Board to fix "a future rate of return to be allowed" to the respondents. As I have pointed out, the Board is required to fix "the price to be paid". In determining this, rate of return is one of several elements which have to be established when a price is being fixed. An application to fix a rate of return divorced from the application to fix rates is not authorized by the Act by which the Board operates.

I have mentioned previously that other ways by which these surpluses could be "dealt with and disposed of" were discussed during the hearing of the appeal. We were asked to consider dispositions of the accumulated surpluses which would not require the company to pay out these funds — crediting these monies against amortization reserve was one such method. It is clear, I think, that all the methods suggested would have the effect of altering the rate base. Like rate of return, rate base can only be considered as a part of the process by which "the just and reasonable price" is to be arrived at, and cannot be considered except on and as part of an application to fix prices.

A judgment of this Division, *Wainwright Gas Co.* v. *Wainwright & Bd. Public Utility Com'rs,* [1930] 4 D.L.R. 1000, 25 A.L.R. 181 [affd [1931] 4 D.L.R. 80] was relied upon by the appellants. Mitchell J.A. in delivering the majority judgment, appears to have approved procedures which took into account prior profits to the company in fixing future rates. Hyndman J.A., dissenting took the

1959 CanLII 308 (AB CA)

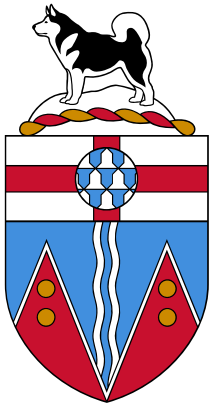
opposite view. The only question before the Court on that appeal was whether there was a matter of law to give the Court jurisdiction to hear the appeal. It was held that there was not; a consideration of the correctness of the Board's procedure was not before the Court and any comments concerning it were clearly *obiter dicta*.

The appeal is dismissed with costs to be taxed on col. 5.

Appeal dismissed.

1959 CanLII 308 (AB CA)

TAB 11



PUBLIC UTILITIES ACT

RSY 2002, c. 186

UNOFFICIAL CONSOLIDATION OF THE STATUTES OF YUKON

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LRY 2002, ch. 186

CODIFICATION NON OFFICIELLE DES LOIS DU YUKON

PUBLIC UTILITIES ACT

RSY 2002, c. 186; amended by SY 2012, c.14; SY 2014, c.3

Please Note: This document, prepared by the Yukon Legislative Counsel Office, is an unofficial consolidation of this Act and includes any amendments to the Act that are in force and is current to: currency date.

For information concerning the date of assent or coming into force of the Act or any amendments, please see the Table of Public Statutes and the Annual Acts on the laws.yukon.ca web site. Links to amending legislation, where appropriate, are provided at the end of each section in this document.

If you find any errors or omissions in this consolidation, please contact:

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LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

LRY 2002, ch. 186; modifiée par LY 2012, ch. 14; LY 2014, ch.3

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PUBLIC UTILITIES ACT

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

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PUBLIC UTILITIES ACT

1 Interpretation

(1) In this Act,

"**board**" means the Yukon Utilities Board established by section 2; « *Régie* »

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

"**costs**" includes fees, counsel fees, and expenses; « *dépens* »

"**customer**" refers to a purchaser of electricity; « *client* »

"**excluded undertaking**" means a prescribed undertaking or an undertaking that consists only of

(a) generation and distribution by a person of electricity, if

(i) the electricity is consumed only by the person, their employees or their tenants, and

(ii) if the electricity is generated on one property and consumed on another

(A) the electricity is carried between the properties by a transmission or distribution line that the person owns and operates, and

LOI SUR LES ENTREPRISES DE SERVICE PUBLIC

1 Définitions

(1) Les définitions qui suivent s'appliquent à la présente loi.

« **audience publique** » Audience pour laquelle un avis public a été donné, qui est ouverte au public et à laquelle peut être entendue la personne dont la Régie décide qu'elle est un intéressé. "*public hearing*"

« **client** » Acheteur d'électricité. "*customer*"

« **dépens** » S'entend notamment des frais et honoraires d'avocat. "*costs*"

« **entreprise de service public** » ou « **entreprise** » S'entend d'une personne, à moins qu'elle n'agisse dans une entreprise exclue, qui remplit l'une des conditions suivantes :

a) au Yukon et pour une contrepartie, elle génère, produit, emmagasine, achemine, vend, livre ou fournit de l'électricité ou du gaz;

b) elle est propriétaire d'équipements ou d'installations qui sont utilisés pour faire toute chose indiquée à l'alinéa a). "*public utility*"

« **entreprise exclue** » S'entend d'une entreprise visée par règlement ou d'une entreprise qui limite ses activités à l'un des secteurs d'activités suivants :

a) la production et la distribution d'électricité par une personne, lorsque les conditions suivantes s'appliquent :

(i) l'électricité est consommée seulement pa cette personne, ses employés ou ses locataires,

(ii) lorsque l'électricité est produite sur une

(B) the resulting electrical system

(I) is connected with the facilities neither of a public utility nor of any other customer, and

(II) does not duplicate any existing or planned facility of a public utility,

(b) engagement in the petroleum industry or in the well-head production of oil, natural gas, or other natural petroleum substances, or

(c) the sale or delivery of gas otherwise than by a pipeline; « *entreprise exclue* »

"**expenses**" includes expenses of the board; « *frais* »

"**gas**" means methane and propane; « *gaz* »

"**member**" means a member of the board; « *membre* »

"**methane**" means, in addition to its normal scientific meaning, a mixture mainly of methane which ordinarily may contain some ethane, nitrogen, helium, or carbon dioxide; « *méthane* »

"**propane**" means, in addition to its normal scientific meaning, a mixture mainly of propane which ordinarily may contain some ethane or butanes; « *propane* »

"**public hearing**" means a hearing of which public notice is given, which is open to the public, and at which any person the board determines has an interest in the matter may be heard; « *audience publique* »

"**public utility**" means a person who, otherwise than in an excluded undertaking

(a) in the Yukon, for consideration, produces, generates, stores, transmits, sells, delivers or furnishes electricity or gas, or

(b) owns equipment or facilities that are used to do anything described in paragraph (a); « *entreprise de service public* » or « *entreprise* »

"**rate**" includes a general, individual, or joint rate, fare, toll, charge, rental, or other compensation charged or chargeable by a public utility, any rule, regulation, practice, measurement, classification, or contract of a public utility relating to a rate, and any schedule or tariff respecting a rate; « *taux* »

"**service**" includes the use and accommodation

propriété et consommée sur une autre

(A) l'électricité est transportée entre les propriétés par des lignes de transmission ou de distribution dont cette personne est le propriétaire-exploitant,

(B) le système électrique qui en découle :

(I) n'est pas relié à une entreprise de service public ou à tout autre client,

(II) ne fait pas double emploi avec les établissements existants ou à venir d'une enterprise de service public;

b) la participation à l'industrie des hydrocarbures ou à l'extraction à la tête de puits de pétrole, de gaz naturel ou d'autres hydrocarbures naturels;

c) la vente ou la livraison du gaz autrement que par un pipeline. "*excluded undertaking*"

« **frais** » S'entend des frais de la Régie. "*expenses*"

« **gaz** » Le méthane et le propane. "*gas*"

« **membre** » Membre de la Régie. "*member*"

« **méthane** » S'entend, en plus de son acception scientifique courante, d'un mélange composé principalement de méthane et pouvant contenir de l'éthane, de l'azote, de l'hélium ou du bioxide de carbone. "*methane*"

« **propane** » S'entend, en plus de son acception scientifique courante, d'un mélange composé principalement de propane et pouvant contenir de l'éthane, ou des butanes. "*propane*"

« **Régie** » La Régie des entreprises de service public du Yukon constituée par l'article 2. "*board*"

« **redevance** » Toute contrepartie payée, payable, promise, demandée, reçue ou attendue — directement ou indirectement — par une entreprise de service public; y sont assimilés la promesse ou l'engagement par une entreprise de service public d'offrir un service en contrepartie d'une proposition ou d'un contrat visant l'aliénation d'un bien-fonds ou d'intérêts sur celui-ci, ou comme stipulation d'une telle proposition ou d'un tel contrat. "*compensation*"

« **service** » Y sont assimilés l'usage et les locaux, les

provided and a product or commodity furnished by a public utility, and also the plant, equipment, apparatus, appliances, property, and facilities employed by or in connection with a public utility in providing service or in furnishing a product or commodity for the purposes in which the public utility is engaged. « *service* »

produits ou marchandises fournis par une entreprise de service public, ainsi que les usines, équipements, appareils, biens et installations qu'elle utilise relativement à la fourniture du service ou des produits ou marchandises dans la réalisation de l'activité de l'entreprise de service public. "*service*"

« **taux** » Redevance — générale, individuelle ou conjointe — qu'exige ou que peut exiger une entreprise de service public; la présente définition vise également les règles, règlements, pratiques, mesures, catégories, classes ou contrats y afférents, ainsi que les barèmes et tarifs correspondants. "*rate*"

(2) In this section, a reference to a person includes any lessee, trustee, receiver or liquidator of the person.

[S.Y. 2014, c.3, s.2] [S.Y. 2002, c. 186, s. 1]

(2) Au présent article, le terme « personne » vise également le preneur, le syndic, le séquestre ou le liquidateur de cette personne.

[L.Y. 2014, ch. 3, art. 2] [L.Y. 2002, ch. 186, art. 1]

PART 1

YUKON UTILITIES BOARD

2 Yukon Utilities Board

(1) The Yukon Utilities Board is established, composed of not fewer than three nor more than five persons appointed by the Minister.

(2) The board is responsible to the Minister for the administration of this Act.

(3) For the purpose of carrying out the duties and exercising the powers imposed or conferred on it under this Act, the board may enter into contracts with the Government of the Yukon.

[S.Y. 2002, c. 186, s. 2]

3 Term of office

(1) The term of office for which a member may be appointed is three years.

(2) A member is eligible for re-appointment on the expiration of their term of office.

[S.Y. 2002, c. 186, s. 3]

4 Substitute members

(1) The Minister may appoint a substitute member to act in the place of a member who is for any reason unable to perform their duties.

PARTIE 1

RÉGIE DES ENTREPRISES DE SERVICE PUBLIC

2 Constitution

(1) Est constituée la Régie des entreprises de service public du Yukon composée de trois à cinq membres nommés par le ministre.

(2) La Régie est responsable de l'application de la présente loi. À ce titre, elle relève du ministre.

(3) Aux fins de l'exécution de ses obligations et de l'exercice de ses pouvoirs qui lui sont imposés ou attribués en vertu de la présente loi, la Régie peut conclure des contrats avec le gouvernement du Yukon.

[L.Y. 2002, ch. 186, art. 2]

3 Mandat

(1) Le mandat des membres est de trois ans.

(2) Le mandat des membres est renouvelable.

[L.Y. 2002, ch. 186, art. 3]

4 Suppléance

(1) Le ministre peut nommer un suppléant pour remplacer le membre incapable d'agir.

(2) When a substitute member is appointed under subsection (1), the substitute member may attend all meetings of the board even though there is no vacancy in the permanent membership, but shall not vote unless one of the permanent members is absent.

[S.Y. 2002, c. 186, s. 4]

(2) Le suppléant peut assister aux réunions de la Régie, même s'il n'y a pas de vacance en son sein, mais il ne peut voter qu'en l'absence d'un membre régulier.

[L.Y. 2002, ch. 186, art. 4]

5 Expenses of members

A member may be paid transportation, accommodation, and living expenses incurred in connection with the performance of their duties as a member of the board away from their ordinary place of residence but, except as otherwise provided by the regulations, the payment of those expenses shall conform as nearly as possible in all respects to the payment of those expenses for members of the public service of the Yukon.

[S.Y. 2002, c. 186, s. 5]

5 Frais

Les membres ont droit aux frais de déplacement et de séjour entraînés pour l'accomplissement de leurs fonctions hors de leur lieu ordinaire de résidence; sauf disposition contraire des règlements, le remboursement de ces frais se conforme autant que possible au remboursement de frais semblables aux fonctionnaires du Yukon.

[L.Y. 2002, ch. 186, art. 5]

6 Chair and vice-chair

(1) The Minister shall appoint one of the members to be the chair and another to be the vice-chair.

(2) The chair is the chief executive officer of the board, and shall

(a) supervise and direct the work of the board; and

(b) preside at sittings of the board.

(3) If the chair is unable at any time for any reason to exercise the powers or perform the duties of office, the vice-chair may act in place of the chair.

[S.Y. 2002, c. 186, s. 6]

6 Président et vice-président

(1) Le ministre choisit parmi les membres le président et le vice-président.

(2) Le président est le premier dirigeant de la Régie; à ce titre, il en assure la direction et préside ses réunions.

(3) En cas d'empêchement du président, le vice-président assume la présidence.

[L.Y. 2002, ch. 186, art. 6]

7 Board meetings

(1) The board shall meet at the call of the chair, who shall convene any meetings necessary for the conduct of the business of the board.

(2) Despite subsection (1), the board shall meet at least twice a year.

[S.Y. 2002, c. 186, s. 7]

7 Réunions de la Régie

(1) La Régie se réunit à l'initiative du président; celui-ci convoque les réunions nécessaires à la conduite de ses activités.

(2) La Régie doit toutefois se réunir au moins deux fois l'an.

[L.Y. 2002, ch. 186, art. 7]

8 Decisions of the board

(1) A majority of the members is a quorum, but no quorum exists unless the chair or vice-chair is present.

8 Décisions de la Régie

(1) La majorité des membres constitue le quorum, le président ou le vice-président devant être présent.

(2) Subject to subsection (1), a decision of a majority of the members present at a meeting of the board is a decision of the board, but in the event of an evenly divided opinion between members including the chair, the matter shall be decided in accordance with the vote of the chair.

[S.Y. 2002, c. 186, s. 8]

(2) Sous réserve du paragraphe (1), la décision de la majorité des membres présents à une réunion de la Régie vaut décision de la Régie; en cas de partage, le président a voix prépondérante.

[L.Y. 2002, ch. 186, art. 8]

9 Vacancies in the membership of the board

A vacancy in the membership reduces the number of members required for a quorum and, subject to section 8, does not impair the right of the remaining members to act.

[S.Y. 2002, c. 186, s. 9]

9 Vacance

Les vacances réduisent le nombre de membres requis pour le quorum et, sous réserve de l'article 8, n'entravent pas son fonctionnement.

[L.Y. 2002, ch. 186, art. 9]

10 Rules of the board

(1) Subject to this Act, the board may by order make rules respecting

(a) the conduct of its meetings and business;

(b) the notices authorized or required to be given under this Act;

(c) the records to be kept in respect of its business, including the custody, preservation, and provision of access to those records;

(d) the procedure for making applications and representations to the board;

(e) the conduct of hearings by or before the board;

(f) the filing and investigation of complaints, including the information to be provided in support of complaints; and

(g) generally, the procedures of the board and any other matter that reasonably is necessary for the effective and orderly conduct of the business of the board.

(2) Orders under this section shall be published in the *Yukon Gazette*.

[S.Y. 2002, c. 186, s. 10]

10 Règles

(1) Sous réserve des autres dispositions de la présente loi, la Régie peut, par ordonnance, établir des règles concernant :

a) la tenue de ses réunions et la conduite de ses activités;

b) les avis à donner en application de la présente loi;

c) les livres à tenir relativement à ses activités, y compris la garde, la conservation de ceux-ci et l'accès à ceux-ci;

d) la procédure applicable à la présentation des demandes et au dépôt des observations faites à la Régie;

e) la conduite des audiences par elle ou devant elle;

f) le dépôt de plaintes, y compris les renseignements à donner au soutien de celles-ci, et les enquêtes y afférentes;

g) de façon générale, sa procédure et toute autre question qui, d'une manière raisonnable, est nécessaire à la bonne conduite de ses activités.

(2) Les ordonnances visées au présent article sont publiées dans la *Gazette du Yukon*.

[L.Y. 2002, ch. 186, art. 10]

11 Conflict of interest

(1) If a member has a direct or indirect personal interest in a matter or a corporation under review by

11 Conflit d'intérêts

(1) Les membres qui ont un intérêt personnel même indirect dans une affaire ou une personne morale

the board, that member shall refrain from participating in any way in the review of the matter or corporation by the board.

(2) A member shall not, directly or indirectly,

(a) hold or acquire a beneficial interest in any share or other security of a corporation or other person subject to regulation under this Act;

(b) have a significant beneficial interest in all or part of any article or process that is required or used by a corporation or other person referred to in paragraph (a) for the purpose of its equipment or service; or

(c) have a significant beneficial interest in a contract for the construction of works or the furnishing of a service for or by a corporation or other person referred to in paragraph (a).

(3) A member in whom a beneficial interest referred to in subsection (2) is or becomes vested shall, within three months after the member's appointment or acquisition of the property, as the case may be, divest themselves of the interest.

(4) The use or purchase for personal or domestic purposes of heat, light, power, electricity, or gas or service from a corporation or other person subject to regulation under this Act is not a contravention of this section and does not disqualify a member from acting in any matter affecting the corporation or other person.

[S.Y. 2002, c. 186, s. 11]

faisant l'objet d'une enquête par la Régie sont tenus de s'abstenir d'y participer.

(2) Les membres ne peuvent, même indirectement :

a) détenir ou acquérir un intérêt à titre de bénéficiaire dans une action ou autre titre d'une personne morale ou autre assujettie à la réglementation sous le régime de la présente loi;

b) avoir un intérêt important à titre de bénéficiaire dans tout ou partie d'un bien ou procédé qui est requis ou utilisé par une personne morale ou autre mentionnée à l'alinéa a) aux fins de son équipement ou de son service;

c) avoir un intérêt important à titre de bénéficiaire dans un contrat de construction d'ouvrage ou de fourniture de service par ou pour une personne morale ou autre mentionnée à l'alinéa a).

(3) Le membre qui devient investi d'un tel intérêt est tenu de s'en départir dans les trois mois de sa nomination ou de l'acquisition du bien.

(4) L'utilisation ou l'achat à des fins personnelles ou domestiques de chauffage, d'éclairage, d'électricité ou de gaz ou d'un service d'une personne morale ou autre assujettie à la réglementation sous le régime de la présente loi ne constitue pas une violation du présent article et n'a pas pour effet d'empêcher un membre d'agir dans les affaires visant la personne morale ou cette autre personne.

[L.Y. 2002, ch. 186, art. 11]

12 Confidentiality of board information

(1) Every member and every official of the board, and every person involved in the administration of this Act, shall keep confidential from all other persons all information acquired by them in confidence in the course of their duties, except insofar as disclosure is necessary for the administration of this Act or the board authorizes the release of the information.

12 Confidentialité

(1) Les membres et le personnel de la Régie ainsi que quiconque œuvre à l'application de la présente loi sont tenus à la confidentialité pour tous les renseignements portés à leur connaissance à titre confidentiel dans le cadre de leurs fonctions, sauf si la communication est nécessaire à l'application de la présente loi ou si la Régie en autorise la communication.

(2) No person referred to in subsection (1) shall be required to testify in a civil action to which the board is not a party about information obtained by the person in the discharge of their duty.

[S.Y. 2002, c. 186, s. 12]

(2) Les personnes mentionnées au paragraphe (1) ne peuvent être tenues de témoigner dans une action civile à laquelle la Régie n'est pas partie relativement à des renseignements obtenus dans le cadre de leurs fonctions.

[L.Y. 2002, ch. 186, art. 12]

13 Board staff and records

(1) The board may, despite the *Public Service Act*, make provision for a secretary to the board and for other administrative support services.

(2) The secretary shall

(a) keep a record of the proceedings of the board;

(b) ensure that copies of every rule and order of the board are filed in the records of the board; and

(c) carry out the instructions and directions of the board under this Act or the regulations respecting the secretary's duties or office.

(3) On the application of any person who pays the prescribed fee, the secretary shall give that person a certified copy of any rule or order of the board, or report of the board under section 19.

(4) The board may appoint an acting secretary in the absence of the secretary.

(5) The board may use any premises it considers necessary from time to time for its efficient operation.

[S.Y. 2002, c. 186, s. 13]

13 Personnel et livres

(1) Malgré la *Loi sur la fonction publique*, la Régie peut prévoir la nomination d'un secrétaire et du personnel de soutien.

(2) Le secrétaire :

a) tient le relevé des délibérations de la Régie;

b) verse aux livres de la Régie copie de ses règles et ordonnances;

c) met en œuvre les instructions et directives de la Régie données sous le régime de la présente loi ou des règlements relativement à ses attributions.

(3) Sur demande de quiconque paie les droits prescrits, le secrétaire est tenu de lui remettre une copie certifiée de toute règle ou ordonnance de la Régie ou d'un rapport fait en application de l'article 19.

(4) La Régie peut nommer un secrétaire intérimaire en l'absence du titulaire.

(5) La Régie peut utiliser tout lieu dont elle a besoin, selon elle, pour son fonctionnement efficace.

[L.Y. 2002, ch. 186, art. 13]

14 Technical assistance

The board may from time to time engage one or more persons having special, technical, or other knowledge to inquire into and report to it on any matter arising in connection with its business.

[S.Y. 2002, c. 186, s. 14]

14 Expertise

La Régie peut, le cas échéant, retenir les services d'un ou plusieurs experts en vue de faire enquête et rapport sur tout aspect relatif à ses activités.

[L.Y. 2002, ch. 186, art. 14]

15 Inquiry by board member

(1) The board or the chair may authorize one or more of the members to inquire into and report to the board on any question or matter arising in connection with the business of the board.

15 Enquête par un membre

(1) La Régie ou le président peut autoriser un ou plusieurs membres à faire enquête et rapport sur toute question liée à ses activités.

(2) A member authorized pursuant to this section to report to the board on a question has and may exercise all the powers of the board for the purpose of taking evidence or acquiring the necessary information for the purposes of their report.

(3) The report of a member under this section may be adopted as an order of the board or otherwise dealt with as the board considers proper.

[S.Y. 2002, c. 186, s. 15]

(2) Ce membre dispose de tous les pouvoirs de la Régie en matière de preuve ou pour recueillir les renseignements nécessaires à l'établissement de son rapport.

(3) Le rapport peut être adopté au même titre qu'une ordonnance de la Régie ou être traité selon ce que celle-ci estime indiqué.

[L.Y. 2002, ch. 186, art. 15]

16 Use of public service by the board

(1) Subject to subsection (2), for the purpose of carrying out the duties and exercising the powers imposed or conferred on it under this Act, the board may avail itself of the services of any officer or employee of any board, commission, agency, or department of the Government of the Yukon.

(2) Every officer or employee of a board, commission, agency, or department of the Government of the Yukon shall give to the board whatever service, assistance, and information they are able to give and the board requires, subject to the approval of the Minister in charge of the administration of the service in which the officer or employee is employed.

[S.Y. 2002, c. 186, s. 16]

16 Utilisation des fonctionnaires

(1) Sous réserve du paragraphe (2), la Régie peut, pour l'exercice de ses fonctions et de ses pouvoirs, recourir aux services des agents ou fonctionnaires de tout organisme ou ministère du gouvernement du Yukon.

(2) Ces fonctionnaires sont tenus de donner à la Régie les services, l'aide et les renseignements qu'ils peuvent donner et que la Régie leur demande, sous réserve de l'agrément du ministre responsable de l'administration du service dont ils font partie.

[L.Y. 2002, ch. 186, art. 16]

17 Directions from the Commissioner in Executive Council

(1) Despite any other provision of this Act, the board shall comply with any general or special direction of the Commissioner in Executive Council with respect to the exercise of the powers and functions of the board.

(2) A direction under subsection (1) is a regulation within the meaning of the *Regulations Act*.

(3) The board may request a review of a direction under subsection (1), and on receipt of such a request from the board by the Minister, the Commissioner in Executive Council may

(a) suspend or continue the operation of the direction until the completion of a review; or

(b) confirm, vary, or revoke the direction.

17 Instructions du commissaire en conseil exécutif

(1) Malgré les autres dispositions de la présente loi, la Régie est tenue de se conformer aux instructions générales ou spéciales du commissaire en conseil exécutif relativement à l'exercice de ses pouvoirs et fonctions.

(2) L'instruction est assimilée à un règlement pour l'application de la *Loi sur les règlements*.

(3) La Régie peut demander la révision d'une instruction et, sur réception d'une telle demande par le ministre, le commissaire en conseil exécutif peut suspendre ou proroger l'effet de l'instruction jusqu'à la fin de la révision ou confirmer, modifier ou annuler l'instruction.

(4) The board may, in respect of any matter arising in connection with the business of the board, transmit to the Minister a request that the Commissioner in Executive Council issue a direction under this section.

(5) If a direction is issued under this section during the course of any matter under consideration by the board, any party to the matter

(a) may be granted any adjournment the board considers necessary to deal with any change in circumstances; and

(b) may be awarded any costs the board considers just and fair in the circumstances.

[S.Y. 2002, c. 186, s. 17]

(4) La Régie peut, relativement à toute affaire liée à ses activités, demander au ministre de lui donner des instructions au titre du présent article.

(5) Si une instruction est donnée en application du présent article dans le cadre d'une affaire dont la Régie est saisie, toute partie peut bénéficier d'un ajournement que la Régie estime nécessaire pour lui permettre de répondre à tout changement de circonstances et avoir droit aux frais que celle-ci estime justes dans les circonstances.

[L.Y. 2002, ch. 186, art. 17]

18 Investigations and duties of the board

(1) The board shall conduct any investigations, make any reports and perform any duties, in addition to the duties assigned to it by this Act, that the Minister may request.

(2) If the Minister requests a report from the board on a matter of general public policy, the board may seek any representations from the public or from interested persons or organizations that the board considers appropriate and, subject to section 50, may hold hearings.

(3) A report requested pursuant to subsection (1) shall be delivered within any time specified by the Minister.

(4) A report under this section is not binding on the Executive Council.

[S.Y. 2002, c. 186, s. 18]

18 Enquêtes et obligations de la Régie

(1) La Régie exécute les fonctions — y compris la tenue d'enquêtes et la préparation de rapports — que le ministre peut lui demander en plus de celles qui lui sont assignées par la présente loi.

(2) Si le ministre demande un rapport à la Régie sur une affaire d'intérêt public, celle-ci peut, selon ce qu'elle estime indiqué, demander l'avis du public ou des personnes ou organismes intéressés, et, sous réserve de l'article 50, tenir des audiences.

(3) Le rapport visé au paragraphe (1) est à remettre dans le délai que fixe le ministre.

(4) Le rapport visé au présent article ne lie pas le Conseil exécutif.

[L.Y. 2002, ch. 186, art. 18]

19 Annual report of the board

The board shall make a report to the Minister not later than June 30 in each year on the activities and affairs of the board during the year ending on March 31 of that year.

[S.Y. 2002, c. 186, s. 19]

19 Rapport annuel

Au plus tard le 30 juin, la Régie remet au ministre un rapport sur ses activités pour l'exercice terminé le 31 mars précédant.

[L.Y. 2002, ch. 186, art. 19]

PART 2
REGULATION OF PUBLIC UTILITIES

20 Franchise requirement

No public utility shall operate in the Yukon unless it has been granted a franchise by the Commissioner in Executive Council.

[S.Y. 2002, c. 186, s. 20]

21 Grant of franchise

(1) The Commissioner in Executive Council may, with the approval of the board and subject to any terms and conditions that the board may recommend,

(a) grant a franchise to a public utility; or

(b) renew, alter, or revoke a franchise granted to a public utility or deemed by section 77 to have been granted.

(2) The board may give its approval for the purposes of subsection (1) if, after hearing representations from, or with the consent of, any persons that the board considers appropriate, the board determines that

(a) the franchise is necessary and proper for the public convenience and properly conserves the public interests;

(b) the scheme proposed is reasonable and sufficient having regard to the general circumstances; and

(c) having regard to the availability of any other source of supply in the area to be served and to any other circumstances, the granting of the franchise is to the general benefit of any area directly or indirectly affected by it.

(3) The board may, in approving the grant, renewal, or alteration of a franchise, recommend the imposition of any terms or conditions as to construction, equipment, maintenance, service, or operation that, in the opinion of the board, the public convenience or interest reasonably requires.

[S.Y. 2002, c. 186, s. 21]

PARTIE 2
RÉGLEMENTATION DES ENTREPRISES DE SERVICE PUBLIC

20 Agrément

Aucune entreprise de service public ne peut être exploitée au Yukon sans l'agrément du commissaire en conseil exécutif.

[L.Y. 2002, ch. 186, art. 20]

21 Octroi de l'agrément

(1) Le commissaire en conseil exécutif peut, sur approbation de la Régie et sous réserve des modalités et des conditions que celle-ci recommande, agréer une entreprise de service public ou renouveler, modifier ou révoquer l'agrément qui lui a été donné ou qui est réputé lui avoir été donné au titre de l'article 77.

(2) La Régie peut donner son approbation aux fins du paragraphe (1) si, après avoir entendu les personnes qu'elle estime indiquées ou sur consentement de celles-ci, elle conclut que :

a) l'agrément est d'intérêt public;

b) le plan proposé est acceptable compte tenu des circonstances générales;

c) compte tenu de la disponibilité de toute autre source d'approvisionnement dans la région à desservir et des autres circonstances, l'agrément profitera généralement à la région directement ou indirectement concernée.

(3) La Régie peut assortir la délivrance, le renouvellement ou la modification de l'agrément des conditions ou modalités qu'elle estime nécessaires à l'intérêt public en matière de construction, d'équipement, d'entretien, de service ou d'exploitation.

[L.Y. 2002, ch. 186, art. 21]

22 Interim permission

Despite section 20, if in respect of any place no franchise has been granted, the board may recommend to the Commissioner in Executive Council that an interim permission be granted to a person to operate a public utility, subject to any terms and conditions that the board may recommend.

[S.Y. 2002, c. 186, s. 22]

23 Books and records of public utilities

(1) Every public utility shall

(a) keep any books, records, and accounts that afford a reasonable understanding of the conduct of its business; and

(b) maintain depreciation, amortization, and depletion accounts in accordance with any rates and methods that the board directs.

(2) A public utility shall not change its accounting practices under subsection (1) except with the prior approval of the board.

[S.Y. 2002, c. 186, s. 23]

24 Review by the board

(1) The board may review the affairs, earnings, and accounts of any public utility.

(2) A person whose interest, in the opinion of the board, is affected or likely to be affected by the result of a review is entitled, on payment of reasonable costs, to obtain from the board the result of the review, including all information in the board's possession in respect of the earnings of the public utility.

[S.Y. 2002, c. 186, s. 24]

25 Reports to the board

(1) Every public utility shall, within three months after the end of each of its financial years, file with the board

(a) a statement showing its rates;

(b) financial statements for the financial year in the form and verified in the manner directed by the board; and

(c) a statement setting forth the name, address, and duties of every officer and every director of the public utility.

22 Permission temporaire

Malgré l'article 20, si, relativement à un lieu donné, aucun agrément n'a été délivré, la Régie peut recommander au commissaire en conseil exécutif la délivrance, selon les modalités et aux conditions qu'elle recommande, d'une permission temporaire pour l'exploitation d'une entreprise de service public.

[L.Y. 2002, ch. 186, art. 22]

23 Livres et registres des entreprises

(1) Les entreprises de service public sont tenues de tenir les livres, registres et comptes suffisants pour permettre de comprendre raisonnablement la conduite de leurs activités et de maintenir des comptes de dépréciation, d'amortissement et d'épuisement conformes aux taux et méthodes que la Régie prescrit.

(2) Une entreprise de service public ne peut modifier ses pratiques comptables sans l'approbation préalable de la Régie.

[L.Y. 2002, ch. 186, art. 23]

24 Examen par la Régie

(1) La Régie peut examiner les affaires, les revenus et les comptes des entreprises de service public.

(2) La personne dont l'intérêt est, selon la Régie, visé ou risque d'être visé à la suite de l'examen a droit, sur paiement des frais raisonnables, de se faire communiquer le résultat de l'examen, y compris les renseignements qui sont en la possession de la Régie relativement au revenu de l'entreprise.

[L.Y. 2002, ch. 186, art. 24]

25 Rapport à la Régie

(1) Les entreprises de service public sont tenues de déposer auprès de la Régie, dans les trois mois de la fin de leur exercice :

a) un énoncé de leurs taux;

b) le bilan pour l'exercice en la forme et après la vérification que la Régie prescrit;

c) une déclaration portant les noms, adresses et fonctions des dirigeants et administrateurs de l'entreprise.

(2) A public utility shall notify the board within 10 days of every change in its officers or directors.

[S.Y. 2002, c. 186, s. 25]

(2) Les entreprises de service public sont tenues de communiquer dans les 10 jours tout changement parmi leurs dirigeants ou administrateurs.

[L.Y. 2002, ch. 186, art. 25]

26 Maintenance of property and equipment

Every public utility shall maintain its property and equipment in such a condition as to provide safe, adequate, and proper service.

[S.Y. 2002, c. 186, s. 26]

26 Entretien

Les entreprises de service public sont tenues de conserver leurs biens et équipements dans un état qui leur permet d'offrir un service sûr, suffisant et efficace.

[L.Y. 2002, ch. 186, art. 26]

27 Board orders

The board may make orders

(a) setting rates of a public utility;

(b) prohibiting or limiting any proposed rate change;

(c) setting proper and adequate rates and methods of depreciation, amortization, or depletion in respect of the property of any public utility;

(d) setting just and reasonable standards, classifications, regulations, practices, measurements, or services to be observed, provided, or followed by a public utility;

(e) determining the areas to which a public utility shall provide service, and requiring the public utility to establish, construct, maintain, and operate any reasonable expansion of its existing services; and

(f) determining the conditions that may be imposed by a public utility to establish, construct, maintain, or operate an expansion of its existing services.

[S.Y. 2002, c. 186, s. 27]

27 Ordonnances

La Régie peut, par ordonnance :

a) fixer les taux d'une entreprise de service public;

b) interdire ou restreindre tout projet de modification des taux;

c) fixer un taux acceptable et des méthodes de dépréciation, d'amortissement ou d'épuisement pour les biens d'une entreprise de service public;

d) fixer des normes raisonnables, des catégories, règlements, pratiques, mesures ou services à observer, à offrir ou à suivre par une entreprise de service public;

e) déterminer les zones où une entreprise de service public devra offrir le service et exiger qu'elle établisse, construise, entretienne et exploite toute extension raisonnable de ses services existants;

f) fixer les conditions à imposer par l'entreprise de service public pour établir, construire, maintenir ou exploiter une telle extension de ses services existants.

[L.Y. 2002, ch. 186, art. 27]

28 Rate changes

(1) No public utility shall charge any rate for the supply of the service for which it is franchised other than the rate set by the board pursuant to this Act unless, 90 days before it proposes to charge a different rate,

(a) a statement showing the new rate is filed with the board; and

(b) a notice showing the new rate is sent by mail or delivered to each municipality in which the service is provided and to the Minister.

(2) No public utility shall begin to charge a new rate except on receipt from the board of an order or interim order authorizing it to do so.

[S.Y. 2002, c. 186, s. 28]

28 Modifications des taux

(1) Une entreprise de service public ne peut exiger, pour la fourniture d'un service agréé, un taux autre que celui fixé par la Régie en application de la présente loi, à moins que 90 jours précédant la prise d'effet de la modification, une déclaration indiquant le nouveau taux ne soit déposée auprès de la Régie et qu'un avis mentionnant le nouveau taux ne soit expédié par la poste ou remis à chaque municipalité sur le territoire de laquelle le service est offert, ainsi qu'au ministre.

(2) Une entreprise ne peut exiger un nouveau taux sans avoir reçu de la Régie une ordonnance ou une ordonnance provisoire à cet effet.

[L.Y. 2002, ch. 186, art. 28]

29 Factors affecting rates

In setting rates that a public utility is permitted to charge,

(a) the board may consider the revenues and costs of the public utility in the financial year in which the proceedings for setting the rates and charges began or in any period immediately following, without considering the allocation of those revenues and costs to any part of that period;

(b) the board may give effect to that part of any excess of revenue received or deficiency incurred that is in the opinion of the board applicable to the whole of the financial year of the public utility in which the proceeding was initiated as the board considers just and reasonable;

(c) the board may give effect to any part of any excess revenue received or deficiency incurred after the commencement of the proceeding as the board determines has been due to undue delay in the hearing and determining of the matter; and

(d) the board shall by order approve the method by which and the period during which any excess revenue received or deficiency incurred is to be used or dealt with.

[S.Y. 2002, c. 186, s. 29]

29 Critères liés aux taux

Pour l'établissement des taux qu'une entreprise de service public est autorisée à exiger, la Régie :

a) peut considérer les revenus et les dépenses de l'entreprise pour l'exercice au cours duquel la procédure d'établissement des taux et des charges est entamée ou pour la période qui suit, sans tenir compte de la ventilation de ces revenus et dépenses à toute partie de cette période;

b) peut tenir compte de la partie de tout excédent ou déficit qu'elle estime applicable à la totalité de l'exercice au cours duquel la procédure est entamée, selon ce qu'elle estime juste et raisonnable;

c) peut tenir compte de la partie de tout excédent ou déficit réalisé après le début de la procédure qu'elle conclut avoir été causé par un retard indu dans l'audition de l'affaire et son règlement;

d) doit, par ordonnance, approuver la méthode de traitement des excédents ou des déficits et la période liée à ceux-ci.

[L.Y. 2002, ch. 186, art. 29]

30 Guidelines respecting cost increases

(1) The board, by order, may issue guidelines to be followed by any public utility that generates electricity by the use of petroleum products purchased pursuant to a contract under which provision is made for

(a) the progressive increase in their cost to the public utility; or

(b) the redetermination of their cost either by agreement of the parties or pursuant to arbitration.

(2) Guidelines under subsection (1) may make provision for establishing a new schedule of rates to be charged by the public utility occasioned by any change in the cost of petroleum products.

(3) Nothing in this section limits the jurisdiction of the board to set rates under section 27.

(4) This section applies, with any necessary changes, when a public utility purchases electrical power from a producer for distribution and sale to the public.

(5) When a public utility enters into a contract under which provision is made for any of the matters referred to in subsection (1) or (4), it shall file a copy of the contract with the board.

[S.Y. 2002, c. 186, s. 30]

30 Critères liés aux augmentations de frais

(1) La Régie peut, par ordonnance, imposer des lignes directrices à une entreprise de service public qui produit de l'électricité grâce à des produits pétroliers achetés dans le cadre d'un contrat qui en stipule l'augmentation progressive du coût à l'entreprise ou sa redétermination, soit par entente mutuelle des parties, soit à la suite d'un arbitrage.

(2) Ces lignes directrices peuvent prévoir l'établissement d'un nouveau barème de taux à exiger par l'entreprise de service public à la suite du changement du coût des produits pétroliers.

(3) Le présent article n'a pas pour effet de limiter la compétence de la Régie de fixer les taux en application de l'article 27.

(4) Le présent article s'applique, compte tenu des adaptations nécessaires, lorsqu'une entreprise de service public achète de l'électricité à un producteur pour distribution et vente au public.

(5) Quand une entreprise de service public conclut un contrat stipulant l'un ou l'autre des points mentionnés aux paragraphes (1) ou (4), elle en dépose copie auprès de la Régie.

[L.Y. 2002, ch. 186, art. 30]

31 Contracts setting rates

Any contract for the supply of a service to a person by a public utility that sets a fixed or variable rate either for a present or future supply of the service is deemed to include a clause under which the board has the jurisdiction, on application of one of the parties, to increase or reduce the rate to a rate that the board considers fair and reasonable.

[S.Y. 2002, c. 186, s. 31]

31 Contrats stipulant les taux

Tout contrat de fourniture, pour l'immédiat ou dans l'avenir, de services à une personne par une entreprise de service public pour un taux fixe ou variable est réputé comporter une clause stipulant que la Régie a compétence, sur demande d'une des parties, pour augmenter ou réduire le taux selon ce qu'elle estime juste et raisonnable.

[L.Y. 2002, ch. 186, art. 31]

32 Rate base of public utilities

(1) The board, by order, shall determine a rate base for the property of a public utility used or required to be used to provide service to the public, and may include a rate base for property under construction, or constructed or acquired, and intended to be used in the future to provide service to the public.

32 Taux de base des entreprises de service public

(1) La Régie fixe, par ordonnance, le taux de base pour les biens d'une entreprise de service public utilisés ou devant être utilisés à la fourniture du service au public et peut inclure un taux de base pour les biens en construction ou construits ou acquis et destinés à être utilisés dans l'avenir à cette fin.

(2) The board, by order, shall set a fair return on the rate base.

(3) In determining a rate base the board shall give due consideration to the cost of the property when first devoted to public utility use, to prudent acquisition cost less depreciation, amortization, or depletion, and to necessary working capital.

(4) In setting the fair return that the public utility is entitled to earn on the rate base, the board shall give due consideration to all those facts that in the opinion of the board are relevant.

(5) Despite the other provisions of this section, the board may adopt any just and reasonable basis for determining a method of calculating a fair return on property that is being constructed or that has been constructed or acquired but is not yet being used to provide service to the public.

[S.Y. 2002, c. 186, s. 32]

(2) La Régie fixe, par ordonnance, un juste rendement sur le taux de base.

(3) Pour fixer le taux de base, la Régie tient compte du coût d'un bien au moment de son affectation à l'utilisation de l'entreprise, du coût d'acquisition raisonnable moins la dépréciation, l'amortissement ou l'épuisement, et du capital nécessaire.

(4) En établissant le rendement équitable auquel l'entreprise a droit sur le taux de base, la Régie tient compte de tous les facteurs qu'elle estime pertinents.

(5) Malgré les autres dispositions du présent article, la Régie peut adopter tout critère juste et raisonnable en vue de déterminer une méthode de calcul du rendement juste sur le bien en construction ou qui, étant construit ou acquis, n'est pas encore utilisé pour fournir un service au public.

[L.Y. 2002, ch. 186, art. 32]

33 Service extensions

(1) The board shall not require a public utility to construct, maintain, or operate an extension of its existing services unless, in the judgment of the board,

(a) the extension is reasonable and practical and will furnish sufficient business to justify the expense of its construction, maintenance, and operation; and

(b) the financial position of the public utility reasonably warrants the capital expenditure required.

(2) The Commissioner in Executive Council may, by direction under section 17, instruct the board to require a public utility to construct, maintain, or operate an extension of its existing services despite subsection (1), but if the Commissioner in Executive Council does so the public utility is not required to construct, maintain, or operate the extension except on the agreement of the Commissioner in Executive Council

(a) to pay any additional expenses incurred by the public utility that are not justified under paragraph (1)(a); and

33 Extension du service

(1) La Régie ne peut exiger d'une entreprise de service public qu'elle construise, entretienne ou exploite une extension de ses services existants, à moins qu'elle n'estime :

a) que l'extension est raisonnable et pratique et offrira suffisamment d'affaires pour justifier les frais de sa construction, de son entretien et de son exploitation;

b) que la situation financière de l'entreprise justifie l'immobilisation requise.

(2) Le commissaire en conseil exécutif peut, par instruction donnée au titre de l'article 17, ordonner à la Régie d'exiger d'une entreprise de service public qu'elle construise, entretienne ou exploite une extension de ses services existants, malgré le paragraphe (1), mais, le cas échéant, l'entreprise n'est pas tenue de construire, d'entretenir ou d'exploiter l'extension, sauf sur accord du commissaire en conseil exécutif :

a) de payer les frais additionnels engagés par l'entreprise qui ne sont pas justifiés au titre de l'alinéa (1)a);

(b) to underwrite any capital expenditure not reasonably warranted under paragraph (1)(b).

[S.Y. 2002, c. 186, s. 33]

b) d'assurer l'immobilisation qui n'est pas raisonnablement justifiée au titre de l'alinéa (1)b).

[L.Y. 2002, ch. 186, art. 33]

34 Joint use of equipment

(1) When it is in the public interest or, as a means of saving expense, it is in the interest of public utilities or telecommunications companies that there be a joint use of poles, conduits, or equipment or other means of distribution, the board may, after notice to all parties concerned, in cases where it is practicable,

(a) order the joint use;

(b) declare the terms of the joint use; and

(c) make any other orders for the convenient carrying out of the work and the operation of the services that use the poles or equipment.

(2) In this section, "**telecommunications**" means any transmission, emission, or reception of signs, signals, writings, images, sounds, data, message, or intelligence of any nature by wire, radio communications, cable, waves, or any electronic, electro-magnetic, or optical means, but does not include the transmission, emission, or reception of broadcasting that is a radiocommunication in which the transmissions are intended for direct reception by the general public, and "**telecommunications company**" means a company that provides any service that is provided principally through telecommunications.

(3) The board shall on the application of a public utility or telecommunications company adjudicate on any dispute arising out of the joint use of any poles, conduits, or equipment pursuant to this section or any prior arrangement between the parties, and may make any order after hearing the parties that may be required.

[S.Y. 2002, c. 186, s. 34]

34 Utilisation conjointe d'équipements

(1) S'il est dans l'intérêt public ou, s'agissant d'épargner de l'argent, dans l'intérêt d'entreprises de service public ou de compagnies de télécommunication d'utiliser conjointement des poteaux, des canalisations ou de l'équipement, ou tout autre moyen de distribution, la Régie peut, après avis donné aux parties intéressées, ordonner l'utilisation conjointe, prononcer les conditions la régissant et prendre toute autre ordonnance pour la bonne réalisation des ouvrages et l'exploitation des services qui utilisent les poteaux ou l'équipement.

(2) Au présent article, « **télécommunication** » vise la transmission, l'émission ou la réception de signes, signaux, écrits, images, sons, données, messages de toute nature par fil, radiocommunication, câble, ondes ou tout moyen électronique, électromagnétique ou optique, mais ne vise pas la transmission, l'émission ou la réception d'une radiodiffusion qui est une radiocommunication dans laquelle la transmission est destinée à la réception par le grand public, et « **compagnie de télécommunication** » vise la compagnie qui fournit un service offert principalement via les télécommunications.

(3) Sur demande d'une entreprise de service public ou d'une compagnie de télécommunication, la Régie tranche tout différend découlant de l'utilisation conjointe au titre du présent article ou de toute entente antérieure entre les parties et rend toute ordonnance qu'elle estime nécessaire après audition de celles-ci.

[L.Y. 2002, ch. 186, art. 34]

35 Exemptions

The Minister may, by order, on the recommendation of the board, exempt a person from any provisions of this Part that the Minister may specify in the order.

[S.Y. 2002, c. 186, s. 35]

35 Exemptions

Le ministre peut, par décret et sur recommandation de la Régie, exempter une personne de telles des dispositions de la présente partie qu'elle y précise.

[L.Y. 2002, ch. 186, art. 35]

PART 3
ENERGY PROJECTS

36 Interpretation

In this Part,

"**energy operation certificate**" means a certificate issued under this Part authorizing the holder of the certificate to operate a regulated project; « *certificat d'exploitation* »

"**energy project**" means

(a) any plant, smelter, refinery, or other undertaking or facility designed to use, convert, or process an energy resource or coal,

(b) a facility for the generation of electricity from the motion of wind or water, or the combustion of natural gas, oil, petroleum products, coal, or plant products or geothermal energy, or

(c) an oil or natural gas transmission pipeline, including all associated structures, machinery, appliances, fixtures, and equipment, and storage and handling facilities; « *projet énergétique* »

"**energy project certificate**" means a certificate issued pursuant to this Part to construct a regulated project; « *certificat de construction* »

"**energy resource**" means natural gas, oil, and all other forms of petroleum and hydrocarbon, in gaseous or liquid state, and electricity; « *ressource énergétique* »

"**regulated project**" means any energy project that the Commissioner in Executive Council considers to be significant in the matter of any form of energy and, by order, designates as a regulated project. « *projet agréé* »

[S.Y. 2002, c. 186, s. 36]

37 Energy project certificate

No person shall construct a regulated project except in accordance with an energy project certificate.

[S.Y. 2002, c. 186, s. 37]

PARTIE 3
PROJETS ÉNERGÉTIQUES

36 Définitions

Les définitions qui suivent s'appliquent à la présente partie.

« **certificat de construction** » Certificat délivré en application de la présente partie en vue de la construction d'un projet agréé. "*energy project certificate*"

« **certificat d'exploitation** » Certificat délivré en application de la présente partie et autorisant son titulaire à exploiter un projet agréé. "*energy operation certificate*"

« **projet agréé** » Projet énergétique que le commissaire en conseil exécutif estime important sur le plan énergétique et désigne tel par décret. "*regulated project*"

« **projet énergétique** »

a) Installation — usine, fonderie, raffinerie ou autre — conçue pour l'utilisation ou la transformation de l'énergie ou du charbon;

b) installation destinée à la production d'électricité par le mouvement du vent ou de l'eau ou la combustion de gaz naturel, de pétrole, de produits pétroliers, de charbon ou de plantes ou d'énergie géothermique;

c) pipeline de transmission de gaz ou de pétrole auquel sont assimilés les constructions, machineries, appareils, accessoires et autres équipements connexes, ainsi que les installations de stockage et de manutention. "*energy project*"

« **ressource énergétique** » Le gaz naturel, le pétrole et toute autre forme de pétrole et d'hydrocarbure, de forme gazeuse ou liquide, ainsi que l'électricité. "*energy resource*"

[L.Y. 2002, ch. 186, art. 36]

37 Certificat de construction

Il est interdit de construire un projet agréé, sauf conformément à un certificat de construction.

[L.Y. 2002, ch. 186, art. 37]

38 Energy operation certificate

No person shall operate a regulated project except in accordance with an energy operation certificate.

[S.Y. 2002, c. 186, s. 38]

38 Certificat d'exploitation

Il est interdit d'exploiter un projet agréé, sauf conformément à un certificat d'exploitation.

[L.Y. 2002, ch. 186, art. 38]

39 Applications for certificates

An application for an energy project certificate or energy operation certificate shall be made to the Minister and shall contain the prescribed information.

[S.Y. 2002, c. 186, s. 39]

39 Demande de certificats

La demande de certificat de construction ou d'exploitation est déposée auprès du ministre avec les renseignements réglementaires.

[L.Y. 2002, ch. 186, art. 39]

40 Review of applications

On receipt of an application, the Minister shall refer the application to the board for a review.

[S.Y. 2002, c. 186, s. 40]

40 Examen des demandes

Sur réception d'une demande, le ministre la remet à la Régie pour examen.

[L.Y. 2002, ch. 186, art. 40]

41 Report and recommendations of the board

(1) On receipt of an application from the Minister under section 40, the board may, subject to subsection (2) and section 50, hold a public hearing in accordance with any terms of reference specified by the Minister, and on conclusion of the review the board shall submit a report and recommendations to the Minister.

(2) The board may, for the purpose of receiving information or evidence that the board considers is of a confidential character, exclude the public from a hearing under this section while it receives that information or evidence.

[S.Y. 2002, c. 186, s. 41]

41 Rapport et recommandations de la Régie

(1) Sur réception de la demande remise à elle par le ministre en application de l'article 40, la Régie peut, sous réserve du paragraphe (2) et de l'article 50, tenir une audience publique conformément aux modalités précisées par celui-ci, et, à la fin de l'examen, elle lui remet un rapport et ses recommandations.

(2) Pour l'application du présent article, la Régie peut prononcer le huis clos pour recueillir des renseignements ou éléments de preuve qu'elle estime confidentiels.

[L.Y. 2002, ch. 186, art. 41]

42 Grant or refusal of applications

(1) On receipt of the report and recommendations of the board, the Minister, may

(a) refuse the application; or

(b) grant the application subject to any terms or conditions the Minister considers to be in the public interest.

(2) The conditions for an energy project certificate under paragraph (1)(b) may include any terms or conditions the Minister considers necessary to be included in an energy operation certificate for the project.

[S.Y. 2002, c. 186, s. 42]

42 Octroi ou refus

(1) Sur réception du rapport et des recommandations de la Régie, le ministre peut refuser la demande ou l'accorder sous réserve des modalités et des conditions qu'il estime d'intérêt public.

(2) Les conditions auxquelles un certificat de construction est assujetti peuvent comporter toutes les modalités et les conditions que le ministre estime nécessaires d'inclure dans un certificat d'exploitation pour le projet.

[L.Y. 2002, ch. 186, art. 42]

43 Report on energy project

(1) On completion of the construction of a regulated project for which an energy project certificate has been issued, the person to whom the certificate was issued shall submit a report to the Minister in accordance with the certificate and the regulations.

(2) On receipt of a report under subsection (1), and on being satisfied that the conditions of the energy project certificate have been substantially complied with, the Minister shall issue an energy operation certificate for the regulated project, and may include in the certificate the terms or conditions referred to in subsection 42(2).

[S.Y. 2002, c. 186, s. 43]

43 Rapport sur un projet énergétique

(1) À la fin des travaux de construction d'un projet agréé ayant fait l'objet d'un certificat de construction, le titulaire est tenu de remettre un rapport au ministre conformément au certificat et aux règlements.

(2) Sur réception du rapport visé au paragraphe (1) et s'il est convaincu que les conditions du certificat de construction ont été pour l'essentiel remplies, le ministre délivre un certificat d'exploitation à l'égard du projet et peut l'assortir des modalités et des conditions mentionnées au paragraphe 42(2).

[L.Y. 2002, ch. 186, art. 43]

PART 4
ADMINISTRATION AND ENFORCEMENT
COMPLAINTS AND INVESTIGATIONS

PARTIE 4
MISE EN ŒUVRE ET CONTRÔLE D'APPLICATION
PLAINTES ET ENQUÊTES

44 Complaints

(1) Any person may file a complaint with the board respecting

(a) the rates of a public utility;

(b) a proposed rate change;

(c) the manner in which a public utility provides service;

(d) the areas to which a public utility provides service; or

(e) the conditions imposed by a public utility to establish, construct, maintain, or operate an expansion of its service.

(2) A copy of every complaint filed with the board shall be served on the public utility to which it applies within the time set by the rules of the board.

[S.Y. 2002, c. 186, s. 44]

44 Plaintes

(1) Quiconque peut déposer une plainte à la Régie relativement :

a) aux taux d'une entreprise de service public;

b) à un projet de modification des taux;

c) à la façon dont une entreprise de service public fournit son service;

d) aux zones dans lesquelles une entreprise de service public fournit son service;

e) aux conditions imposées par l'entreprise de service public pour établir, construire, entretenir ou exploiter une extension de son service.

(2) Un double de chaque plainte déposée à la Régie est signifié à l'entreprise visée dans le délai prévu par les règles de la Régie.

[L.Y. 2002, ch. 186, art. 44]

45 Action on complaints

(1) Subject to section 50, if a complaint is made to the board, the board has the power to determine, generally, whether any action on its part shall or shall not be taken.

(2) The board may decide not to deal with a complaint if it appears to the board that

45 Suivi

(1) Sous réserve de l'article 50, la Régie saisie d'une plainte peut, de façon générale, décider des mesures à prendre pour y donner suite.

(2) La Régie peut décider de ne pas donner suite à une plainte, si elle est convaincue, selon le cas, que :

(a) the complaint is one that could or should be more appropriately dealt with under another Act;

(b) the subject matter of the complaint is trivial, frivolous, or vexatious;

(c) the complaint is made in bad faith; or

(d) the complaint is not within the jurisdiction of the board.

(3) The board may decide not to deal with a complaint if it is of the opinion that the facts on which the complaint is based occurred more than six months before the complaint was filed, unless the board is satisfied that the delay was incurred in good faith and no substantial prejudice will result to any person affected by the delay.

(4) If the board decides not to deal with a complaint, it shall advise the complainant in writing of the decision and the reasons for it.

[S.Y. 2002, c. 186, s. 45]

a) celle-ci pourrait ou devrait être réglée sous le régime d'une autre loi;

b) son objet est dénué de tout fondement, frivole ou vexatoire;

c) la plainte est faite de mauvaise foi;

d) la plainte ne relève pas de sa compétence.

(3) La Régie peut décider de ne pas donner suite à une plainte si elle estime que les faits sur lesquels elle est fondée se sont produits plus de six mois avant son dépôt, sauf si elle est convaincue que le retard s'est produit de bonne foi et qu'aucun préjudice important ne sera causé aux intéressés.

(4) Si elle décide de ne pas donner suite à une plainte, la Régie en avise l'auteur par écrit et lui communique les motifs de sa décision.

[L.Y. 2002, ch. 186, art. 45]

46 Investigation of complaints

Subject to section 45, the board shall, without undue delay, investigate every complaint.

[S.Y. 2002, c. 186, s. 46]

46 Enquêtes

Sous réserve de l'article 45, la Régie fait enquête sur toute plainte dans les meilleurs délais.

[L.Y. 2002, ch. 186, art. 46]

47 Settlement of complaints

(1) If the board considers it appropriate, the board may endeavour to effect a settlement of a complaint.

(2) If a settlement of a complaint is agreed to in writing, signed by the public utility and the complainant, and approved by the board, the settlement binds the parties and its terms are enforceable as an order of the board under this Act.

[S.Y. 2002, c. 186, s. 47]

47 Règlement des plaintes

(1) Si elle l'estime indiqué, la Régie peut faire le nécessaire pour régler la plainte.

(2) Tout règlement d'une plainte accepté par écrit et signé par l'entreprise de service public et le plaignant et agréé par la Régie lie les parties et est assimilé à une ordonnance de la Régie.

[L.Y. 2002, ch. 186, art. 47]

48 Investigation without complaint

The board may, on its own motion, investigate any matter respecting the provision of service by a public utility.

[S.Y. 2002, c. 186, s. 48]

48 Enquête sans plainte

La Régie peut, d'office, faire enquête sur tout aspect touchant la fourniture d'un service par une entreprise de service public.

[L.Y. 2002, ch. 186, art. 48]

49 Investigation procedure

(1) An investigation by the board may be made by a member of the board or its staff who is authorized by the board for the purpose.

49 Procédure

(1) L'enquête de la Régie peut être conduite par un de ses membres ou par son personnel qu'elle autorise à ces fins.

(2) Notice of an investigation shall be given to the public utility under investigation.

(3) The board or a person authorized under subsection (1) may

(a) enter on and inspect at any reasonable time any place, building, works, or other property of a public utility;

(b) require the attendance of any persons the board or the person considers necessary to summon and examine, and take the testimony of those persons;

(c) require the production of any books, plans, specifications, and other documents that the board or the person considers necessary; and

(d) administer oaths, affirmations, or declarations.

[S.Y. 2002, c. 186, s. 49]

(2) Un avis de l'enquête est donné à l'entreprise de service public visée.

(3) La Régie ou la personne autorisée en application du paragraphe (1) peut :

a) pénétrer à toute heure raisonnable dans tout lieu, bâtiment, ouvrage ou autre bien d'une entreprise de service public et le visiter;

b) exiger la présence des personnes qu'elle estime nécessaires, les interroger et recueillir leur témoignage;

c) exiger la production des livres, plans, devis et autres documents qu'elle estime nécessaires;

d) faire prêter les serments et recueillir les déclarations ou affirmations solennelles.

[L.Y. 2002, ch. 186, art. 49]

HEARINGS

50 Requirement for approval

Despite any other provision of this Act, the board shall not hold any inquiry or public hearing under this Act without the advance written approval of the Minister for the necessary expenses.

[S.Y. 2002, c. 186, s. 50]

51 Powers of the board

The board may on its own motion inquire into, hear, and determine any matter or thing respecting the production, transmission, delivery, or furnishing of electricity or gas to the public.

[S.Y. 2002, c. 186, s. 51]

52 Hearing procedure and jurisdiction

Subject to the other provisions of this Act and the regulations and to the need to abide by the fundamental principles of justice, the board in respect to any inquiry or hearing

(a) has the exclusive jurisdiction and authority to determine any question of fact, law, or mixed fact and law required to be decided;

AUDIENCES

50 Approbation obligatoire

Malgré les autres dispositions de la présente loi, la Régie ne peut tenir d'enquête ou d'audience publique sous le régime de la présente loi sans l'approbation écrite préalable du ministre relativement aux frais à engager.

[L.Y. 2002, ch. 186, art. 50]

51 Attributions de la Régie

La Régie peut, d'office, faire enquête et se prononcer sur toute affaire touchant la production, la transmission, la livraison ou la fourniture d'électricité ou de gaz au public.

[L.Y. 2002, ch. 186, art. 51]

52 Procédure des audiences et compétence

Sous réserve des autres dispositions de la présente loi et sous réserve des règlements et des règles de justice naturelle, pour les besoins d'une enquête ou d'une audience, la Régie :

a) a compétence exclusive pour trancher toute question de fait, de droit ou de droit et de fait;

(b) may receive any evidence or other information that it considers appropriate, whether or not the evidence is given under oath or affirmation, and whether or not it would be admissible in a court of law;

(c) has the powers, privileges, and immunities of a board of inquiry under the *Public Inquiries Act*;

(d) may determine the persons to whom notice of the proceedings shall be given; and

(e) may determine its own procedures.

[S.Y. 2002, c. 186, s. 52]

b) peut recueillir des témoignages et tout renseignement qu'elle estime nécessaires, que ces témoignages soient rendus sous serment ou par affirmation solennelle, peu importe s'ils sont ou non admissibles en justice;

c) a les mêmes pouvoirs, privilèges et immunités qu'une commission d'enquête régie par la *Loi sur les enquêtes publiques*;

d) peut décider à qui les avis de l'instance seront donnés;

e) peut fixer sa propre procédure.

[L.Y. 2002, ch. 186, art. 52]

53 Evidence

(1) If the board exercises its power to issue a summons requiring the production in evidence of documents or things it may, on the production of the documents or things before it, adjourn the proceedings to permit the parties to examine the documents or things.

(2) Oral evidence or submissions need not be recorded in written form, but the board shall cause electronic sound recordings to be made of all statements made orally at its public hearings, and shall make those recordings as well as all relevant documents available on reasonable conditions for inspection or copying by any person who so requests, and by any court exercising jurisdiction over the board.

[S.Y. 2002, c. 186, s. 53]

53 Preuve

(1) Si elle exerce son pouvoir de décerner une assignation exigeant la production de documents ou d'objets en preuve, la Régie peut, lors de leur production, ajourner la procédure pour permettre aux parties de les examiner.

(2) Il n'est pas nécessaire de consigner par écrit les témoignages et observations, mais la Régie doit prévoir l'enregistrement électronique de toutes les déclarations faites au cours de ses audiences publiques et rendre ces enregistrements ainsi que tous les documents pertinents accessibles pour examen ou copie aux conditions qu'elle estime raisonnables à toute personne qui en fait la demande ainsi qu'aux juridictions supérieures par rapport à la Régie.

[L.Y. 2002, ch. 186, art. 53]

54 Disqualification of board members

(1) A member is not disqualified from participating in a public hearing or any other proceeding respecting a complaint because they have previously taken part in any investigation or consideration of the subject matter of the complaint before the hearing unless they have communicated directly or indirectly with any party or their representative without notice to and opportunity for all parties to participate before any final decision.

(2) Despite subsection (1), the board or a member may seek legal advice from an advisor independent of the parties, but in that case the nature of the advice shall be made known to the parties in order that they may make submissions as to the law.

[S.Y. 2002, c. 186, s. 54]

54 Empêchement

(1) Un membre n'est pas empêché de participer à une audience publique ou à toute autre procédure touchant une plainte parce qu'il a auparavant participé à toute enquête ou à l'examen de l'objet de la plainte avant l'audience, à moins qu'il n'ait communiqué, même indirectement, avec une partie ou son représentant sans avoir donné avis aux autres parties et leur avoir donné la possibilité d'y participer avant la décision définitive.

(2) Malgré le paragraphe (1), la Régie ou un de ses membres peut demander l'avis juridique d'un conseiller indépendant des parties, mais, dans ce cas, la nature de l'avis est communiquée aux parties de sorte qu'elles puissent faire valoir leurs observations quant au droit.

[L.Y. 2002, ch. 186, art. 54]

55 Combination of proceedings

The board may combine two or more complaints or other matters under this Act and deal with them in the same proceeding if

(a) they relate to the same public utility; or

(b) they have questions of law or fact in common.

[S.Y. 2002, c. 186, s. 55]

56 Costs

The board may order to whom or by whom any costs incidental to any proceeding before the board are to be paid, and may set the costs to be paid.

[S.Y. 2002, c. 186, s. 56]

ORDERS

57 Powers of the board

The board may make any order authorized under this Part on its own motion, or on the complaint or application of an interested person.

[S.Y. 2002, c. 186, s. 57]

58 Types of orders

(1) The board may order any person to do anything that the person is or may be required to do under this Act, and may forbid the doing of anything that is contrary to this Act.

(2) An order issued under subsection (1) may prescribe the time and the manner in which the order is to be carried out.

[S.Y. 2002, c. 186, s. 58]

59 Extension of time for compliance

If the circumstances of the case so require the board may, on any notice to persons affected that it considers reasonable, or in its discretion without notice, extend the time specified in any board order or decision for compliance with the order or decision.

[S.Y. 2002, c. 186, s. 59]

55 Jonction

La Régie peut combiner deux ou plusieurs plaintes ou toute autre affaire prévue par la présente loi et les traiter dans la même procédure, si elles visent la même entreprise ou si elles ont en commun des points de droit ou de fait.

[L.Y. 2002, ch. 186, art. 55]

56 Dépens

La Régie peut fixer le montant des dépens et déterminer à la charge de qui ils seront.

[L.Y. 2002, ch. 186, art. 56]

ORDONNANCES

57 Pouvoirs de la Régie

La Régie peut, d'office, rendre toute ordonnance qu'elle est autorisée à rendre sous le régime de la présente partie ou à la suite d'une plainte ou d'une demande d'un intéressé.

[L.Y. 2002, ch. 186, art. 57]

58 Ordonnances

(1) La Régie peut ordonner à une personne d'accomplir tout acte qu'elle peut ou doit accomplir sous le régime de la présente loi et lui interdire d'accomplir tout acte contraire à celle-ci.

(2) L'ordonnance visée au paragraphe (1) peut fixer les délais et les modalités de son exécution.

[L.Y. 2002, ch. 186, art. 58]

59 Prorogation du délai

Si les circonstances de l'affaire l'exigent, la Régie peut, après avoir donné les avis nécessaires aux intéressés ou même sans délai, proroger le délai fixé dans une ordonnance ou une décision relativement à l'application de celle-ci.

[L.Y. 2002, ch. 186, art. 59]

60 Requirement for a hearing

(1) Except in cases of urgency, of which the board shall be the sole judge, the board shall not without a hearing make any order involving an outlay by, or a loss or deprivation to, a public utility.

(2) If an order under subsection (1) is made without a hearing, the board, on the application of an interested person, shall as soon as practicable hear and reconsider the matter and make any further or other order that it considers advisable.

(3) If any order is made by the board without a hearing, any person affected by the order may, within 10 days of the making of the order or within any further time that the board may allow, apply to the board to amend or rescind the order.

[S.Y. 2002, c. 186, s. 60]

60 Audience obligatoire

(1) Sauf en cas d'urgence, dont elle est seule juge, la Régie ne peut, sans tenir d'audience, rendre une ordonnance qui aurait pour effet d'obliger une entreprise de service public à effectuer une dépense ou à subir une perte.

(2) Si elle rend une ordonnance sans tenir d'audience, la Régie est tenue, à la demande de tout intéressé, d'entendre et de réexaminer l'affaire dès que possible et de rendre toute autre ordonnance qu'elle estime nécessaire.

(3) Si elle rend une ordonnance sans tenir d'audience, tout intéressé peut, dans les 10 jours de sa prise, ou dans le délai plus long que la Régie peut lui donner, demander à celle-ci de la modifier ou de l'annuler.

[L.Y. 2002, ch. 186, art. 60]

61 Effect of order on service

(1) Every order and decision of the board is final and binding until changed or amended by the board, but no order of the board shall be effective until a copy of it is served on the person to whom it is directed.

(2) If in any case it is made to appear to the satisfaction of the board that service of any document cannot be made by personal service on a person or, in the case of a corporation, at its head office or chief place of business in the Yukon, the board may allow substituted service by publication in a local newspaper or by prepaid registered or certified mail.

[S.Y. 2002, c. 186, s. 61]

61 Portée des ordonnances

(1) Les ordonnances et les décisions de la Régie sont définitives et obligatoires jusqu'à ce qu'elle les modifie; cependant, aucune ordonnance ne prend effet avant la signification d'une copie à l'intéressé.

(2) Si elle est convaincue que la signification d'un document ne peut être effectuée par signification personnelle ou, dans le cas d'une personne morale, à son siège social ou à son principal établissement au Yukon, la Régie peut ordonner un autre mode de signification par publication d'un avis dans un journal local ou par courrier recommandé ou certifié.

[L.Y. 2002, ch. 186, art. 61]

62 Variation of orders

The board may review, change, or cancel any decision or order made by it, and may re-hear any application or complaint before deciding it.

[S.Y. 2002, c. 186, s. 62]

62 Modification des ordonnances

La Régie peut réviser, modifier ou annuler toute décision ou ordonnance qu'elle a rendue et entendre à nouveau toute demande ou plainte avant d'en décider.

[L.Y. 2002, ch. 186, art. 62]

63 Interim and reserved orders

The board may, in any matter before it,

(a) make any interim orders on appropriate terms that it may consider necessary to facilitate its inquiry or to prevent serious harm occurring before its decision; and

(b) reserve further direction either for an adjourned hearing or for further application.

63 Ordonnances provisoires

La Régie peut, dans toute affaire dont elle est saisie, rendre toute ordonnance provisoire aux conditions qu'elle estime nécessaires en vue de faciliter l'enquête ou de prévenir tout préjudice grave pouvant survenir avant la décision et réserver toute autre directive pour la reprise de l'audience ou pour une autre demande.

[L.Y. 2002, ch. 186, art. 63]

[S.Y. 2002, c. 186, s. 63]

ENFORCEMENT

64 Powers of the board and staff

(1) The board may take any steps necessary for the enforcement of any order made by it.

(2) Subject to the *Public Service Act*, the Minister may, on the request of the board, appoint persons to enforce orders of the board.

[S.Y. 2002, c. 186, s. 64]

65 Appointment of administrator for a public utility

(1) If the board considers it necessary for the enforcement of an order, the board may, with the approval of the Minister, authorize a person appointed under section 64 to act as administrator of the affairs of a public utility.

(2) An administrator may enter on and take possession of the property, books, and offices of a public utility and, until the order has been enforced, may

(a) assume and take over the management of the public utility for and in the interests of the shareholders and the public; and

(b) assume all the powers of the directors and officers of the public utility, including the power to employ and dismiss officers and servants of the public utility.

(3) If an administrator takes possession of a public utility, every officer and employee shall obey the orders of the board or the administrator in the management of the public utility.

(4) The board and the administrator may, on taking possession of a public utility, determine, receive, and pay out all money due or owing by the public utility, and give cheques and receipts for money, to the same extent as the proper officers.

(5) The costs and expenses of proceedings under this section are in the discretion of the board.

[S.Y. 2002, c. 186, s. 65]

CONTRÔLE D'APPLICATION

64 Pouvoirs de la Régie et du personnel

(1) La Régie peut prendre les mesures nécessaires à l'exécution de ses ordonnances.

(2) Sous réserve de la *Loi sur la fonction publique*, le ministre peut, à la demande de la Régie, nommer les agents d'exécution des ordonnances de la Régie.

[L.Y. 2002, ch. 186, art. 64]

65 Nomination d'un administrateur

(1) Si elle l'estime nécessaire à l'exécution d'une ordonnance, la Régie peut, avec l'agrément du ministre, autoriser une personne nommée en application de l'article 64 à agir comme administrateur d'une entreprise de service public.

(2) L'administrateur peut entrer sur les lieux de l'entreprise et prendre possession de ses biens, livres et bureaux et, jusqu'à ce que l'ordonnance ait été exécutée, il peut assurer et prendre en charge sa gestion, compte tenu des intérêts des actionnaires et du public, et exercer les pouvoirs des administrateurs et dirigeants de l'entreprise, y compris le pouvoir de recruter et de congédier les dirigeants et le personnel de l'entreprise.

(3) Si l'administrateur prend possession de l'entreprise, les dirigeants et le personnel sont tenus d'obéir aux ordonnances de la Régie ou de l'administrateur rendues dans le cadre de sa gestion.

(4) La Régie et l'administrateur peuvent, lors de la prise de possession de l'entreprise de service public, déterminer, recevoir et payer les créances et les dettes et émettre des chèques et reçus tout comme pourraient le faire les dirigeants.

(5) Les frais et dépens de la procédure visée au présent article sont laissés à l'appréciation de la Régie.

[L.Y. 2002, ch. 186, art. 65]

66 Enforcement in the Supreme Court

An order of the board becomes an order of the Supreme Court immediately on filing with the clerk of the court of a certified copy of the order, and the order may then be enforced in like manner as any order of the Supreme Court.

[S.Y. 2002, c. 186, s. 66]

66 Exécution à la Cour suprême

Les ordonnances de la Régie deviennent des ordonnances de la Cour suprême sur dépôt auprès du greffier de ce tribunal d'une copie certifiée conforme de celles-ci; elles peuvent dès lors être exécutées comme celles de la Cour suprême.

[L.Y. 2002, ch. 186, art. 66]

67 Evidence of board orders and decisions

In any action or proceeding, a copy of any order or decision of the board purporting to be certified by a member or the secretary to be a true copy is *prima facie* evidence without proof of the signature or the appointment of the secretary or member.

[S.Y. 2002, c. 186, s. 67]

67 Preuve

La copie d'une ordonnance de la Régie censée certifiée copie conforme par un membre ou le secrétaire constitue une preuve *prima facie* sans qu'il soit nécessaire de prouver la signature ou la qualité du signataire.

[L.Y. 2002, ch. 186, art. 67]

68 Offence and penalty

(1) A person who fails to comply with any of the provisions of this Act commits an offence and is liable on summary conviction,

(a) in the case of an individual, to a fine not exceeding $1,000, and in default thereof to imprisonment for a term not exceeding one year; and

(b) in the case of a corporation, to a fine not exceeding $5,000.

(2) Any person who advises, solicits, or persuades, or knowingly instructs, directs, or orders any officer, agent, or employee of a public utility to perform, commit, or do any act that is contrary to an order of the board or to the requirements of this Act, commits an offence and is liable on summary conviction to a fine not exceeding $1,000 or to imprisonment for a term not exceeding one year, or both.

[S.Y. 2002, c. 186, s. 68]

68 Infraction et peine

(1) Quiconque contrevient à la présente loi commet une infraction et est passible, sur déclaration de culpabilité par procédure sommaire :

a) s'agissant d'un particulier, d'une amende maximale de 1 000 $ et, à défaut de paiement, d'un emprisonnement maximal d'un an;

b) s'agissant d'une personne morale, d'une amende maximale de 5 000 $.

(2) Quiconque conseille, demande, persuade ou sciemment demande ou ordonne à tout dirigeant, mandataire ou employé d'une entreprise de service public d'accomplir tout acte qui constitue une contravention à une ordonnance de la Régie ou à la présente loi commet une infraction et est passible, sur déclaration de culpabilité par procédure sommaire, d'une amende maximale de 1 000 $ et d'un emprisonnement maximal d'un an, ou de l'une de ces peines.

[L.Y. 2002, ch. 186, art. 68]

APPEALS

69 Leave to appeal to the Court of Appeal

(1) On application to the Court of Appeal within 30 days of a decision or order of the board or within a further time allowed by the Court of Appeal in special circumstances, the Court of Appeal may grant leave to appeal to that court from the order or decision on a question of law or excess of jurisdiction.

(2) The granting of leave to appeal and the costs of the application are in the discretion of the Court of Appeal.

(3) The applicant shall give notice of the application stating the grounds of appeal to the board, to the Minister, and to any party adverse in interest, at least three clear days before the hearing of the application.

[S.Y. 2002, c. 186, s. 69]

70 Appeal procedure and costs

(1) If leave is granted, the appellant shall, within 15 days, give notice of appeal to the board, to the Minister and to any party adverse in interest.

(2) The board and the Minister may be heard by counsel on the appeal.

(3) Neither the board nor an officer, employee, or agent of the board is liable for costs in respect of an application or appeal under this section.

[S.Y. 2002, c. 186, s. 70]

71 Effect of order or decision under appeal

An appeal to the Court of Appeal shall not of itself stay or suspend the operation of the decision or order appealed from, but either the Court of Appeal or the board has the power to suspend the operation of the decision or order on any terms set by the court or the board, as the case may be.

[S.Y. 2002, c. 186, s. 71]

72 Jurisdiction of the Court of Appeal

(1) The Court of Appeal has the same jurisdiction and powers on appeals as it has for appeals from orders of the Supreme Court.

APPELS

69 Demande d'appel à la Cour d'appel

(1) Sur demande à la Cour d'appel formée dans les 30 jours d'une décision ou d'une ordonnance de la Régie ou dans le délai plus long que la Cour d'appel peut accorder dans des circonstances spéciales, celle-ci peut accueillir la demande d'autorisation d'interjeter appel de l'ordonnance ou de la décision sur une question de droit ou d'excès de compétence.

(2) La Cour d'appel a toute latitude pour accorder l'autorisation d'appeler et les dépens afférents à la demande.

(3) Le demandeur avise la Régie, le ministre et toute partie adverse de sa demande trois jours francs avant l'audition de la demande. L'avis comporte les moyens d'appel.

[L.Y. 2002, ch. 186, art. 69]

70 Procédure et dépens

(1) Si l'autorisation est accordée, l'appelant doit, dans les 15 jours, en aviser la Régie, le ministre et les parties adverses.

(2) La Régie et le ministre peuvent être représentés par avocat lors de l'appel.

(3) Ni la Régie ni ses dirigeants, employés et mandataires ne peuvent être tenus aux dépens relativement à la demande ou à l'appel au titre du présent article.

[L.Y. 2002, ch. 186, art. 70]

71 Effet de l'appel sur la décision ou l'ordonnance

L'appel à la Cour d'appel n'a pas pour effet de suspendre l'effet de la décision ou de l'ordonnance en cause, mais la Cour d'appel ou la Régie peut en suspendre l'effet aux conditions qu'elle peut fixer.

[L.Y. 2002, ch. 186, art. 71]

72 Compétence de la Cour d'appel

(1) La Cour d'appel a la même compétence et les mêmes pouvoirs en appel que ceux qu'elle possède pour les appels des ordonnances de la Cour suprême.

(2) Except as otherwise provided in this Act, appeals shall conform as far as possible with the rules governing appeals from the Supreme Court.

[S.Y. 2002, c. 186, s. 72]

(2) Sauf disposition contraire de la présente loi, les appels sont régis, dans la mesure du possible, par les règles régissant les appels qui frappent les décisions de la Cour suprême.

[L.Y. 2002, ch. 186, art. 72]

73 References to the Court of Appeal

The board may at any stage of its proceedings refer any question of law, jurisdiction, practice, or procedure to the Court of Appeal for hearing and determination.

[S.Y. 2002, c. 186, s. 73]

73 Renvois

La Régie peut en tout état de cause déférer une question de droit, de compétence, de pratique ou de procédure à la Cour d'appel pour audience et avis.

[L.Y. 2002, ch. 186, art. 73]

74 Hearing and determination of appeals

An application, appeal, or reference to the Court of Appeal under this Act shall be heard and determined without delay in a summary way.

[S.Y. 2002, c. 186, s. 74]

74 Audition et règlement des appels

Les demandes, appels ou renvois à la Cour d'appel que prévoit la présente loi sont entendus et tranchés sans délai en procédure sommaire.

[L.Y. 2002, ch. 186, art. 74]

MISCELLANEOUS

DISPOSITIONS DIVERSES

75 Expenditure of public money

No provision of this Act authorizes or requires the expenditure of public money except with the approval of the Minister.

[S.Y. 2002, c. 186, s. 75]

75 Engagement de fonds publics

La présente loi n'a pas pour effet d'autoriser ou d'exiger l'engagement de fonds publics, sauf avec l'agrément du ministre.

[L.Y. 2002, ch. 186, art. 75]

76 Regulations

(1) The Commissioner in Executive Council may make any regulations considered necessary for carrying the purposes and provisions of this Act into effect, including but not limited to regulations that

(a) prescribe undertakings to be excluded undertakings;

(b) in respect of undertakings prescribed under paragraph (a), prescribe how the undertakings are to be developed, connected or operated or impose any other standard, condition or requirement;

(c) provide for the remuneration of members of the board or the reimbursement of their expenses;

(d) prescribe a fee for the provision under subsection 13(3) of a certified copy of a document;

(e) prescribe requirements for applications under section 39 for energy project certificates or

76 Règlements

(1) Le commissaire en conseil exécutif peut prendre les règlements qu'il estime nécessaires ou utiles à la mise en œuvre des objets et des dispositions de la présente loi, notamment :

a) prévoir les entreprises qui sont des entreprises excludes;

b) en ce qui concerne les entreprises exclues prévues à l'alinéa a), déterminer comment elles doivent se développer, être reliées ou exploitées, ou établir toute autre norme, condition ou obligation;

c) fixer la rémunération des membres de la Régie ou le remboursement de leurs frais

d) fixer les droits pour une copie certifiée d'un document en vertu du paragraphe 13(3);

e) établir les exigences qui s'appliquent aux demandes de certificat de construction ou

energy operation certificates;

(f) relate to the jurisdiction and procedures of the board; or

(g) define a word or expression that this Act uses but does not define.

(2) A regulation under subsection (1) may

(a) incorporate by reference, in whole or in part or with modifications, any written standard, protocol, rule, guideline, code or other document, either as it reads on a date specified in the regulation or as it is amended from time to time; or

(b) delegate any matter to, or confer a discretion in respect of any matter on, a person.

[S.Y. 2014, c. 3, s. 3] [S.Y. 2002, c. 186, s. 76]

d'exploitation en vertu de l'article 39;

f) établir la procédure qui s'applique à la Régie et les compétences de cette dernière

g) définir tout terme ou toute expression utilisé dans la présente loi mais qui n'y est pas défini.

(2) Un règlement en vertu du paragraphe (1) peut :

a) incorporer par renvoi, en tout ou en partie ou en les modifiant, toute norme écrite, protocole, règle, directive, code ou tout autre document, soit dans leur version à une date précisée au règlement, soit avec leurs modifications successives;

b) déléguer ou attribuer un pouvoir discrétionnaire à une personne sur toute question.

[L.Y. 2014, ch. 3, art. 3] [L.Y. 2002, ch. 186, art. 76]

77 Existing franchises

(1) The Northern Canada Power Commission is deemed to have been granted a franchise by the Commissioner in Executive Council pursuant to this Act subject to any terms and conditions that have been imposed on or accepted by the Northern Canada Power Commission pursuant to the *Electrical Public Utilities Act* immediately before the coming into force of this Act.

(2) The Yukon Electrical Company Limited is deemed to have been granted a franchise by the Commissioner in Executive Council pursuant to this Act subject to any terms and conditions that have been imposed on or accepted by the Yukon Electrical Company Limited pursuant to the *Electrical Public Utilities Act* immediately before the coming into force of this Act.

(3) The Yukon Hydro Company Limited is deemed to have been granted a franchise by the Commissioner in Executive Council pursuant to this Act subject to any terms and conditions that have been imposed on or accepted by the Yukon Hydro Company Limited pursuant to the *Electrical Public Utilities Act* immediately before the coming into force of this Act.

(4) Nothing in this section limits the power of the Commissioner in Executive Council to revoke or vary the terms or conditions of any franchise granted or deemed to have been granted under this or any other Act.

[S.Y. 2002, c. 186, s. 77]

77 Agréments existants

(1) La Commission d'énergie du Nord canadien est réputée avoir reçu l'agrément du commissaire en conseil exécutif au titre de la présente loi, sous réserve des modalités et des conditions qui lui ont été imposées ou qu'elle a acceptées sous le régime de la loi intitulée *Electrical Public Utilities Act* à l'entrée en vigueur de la présente loi.

(2) La Société Yukon Electrical Company Limited est réputée avoir reçu l'agrément du commissaire en conseil exécutif au titre de la présente loi, sous réserve des modalités et des conditions qui lui ont été imposées ou qu'elle a acceptées sous le régime de la loi intitulée *Electrical Public Utilities Act* à l'entrée en vigueur de la présente loi.

(3) La Société Yukon Hydro Company Limited est réputée avoir reçu l'agrément du commissaire en conseil exécutif au titre de la présente loi, sous réserve des modalités et des conditions qui lui ont été imposées ou qu'elle a acceptées sous le régime de la loi intitulée *Electrical Public Utilities Act* à l'entrée en vigueur de la présente loi.

(4) Le présent article n'a pas pour effet de limiter la compétence du commissaire en conseil exécutif de révoquer ou de modifier les modalités et les conditions d'un agrément accordé ou réputé accordé sous le régime de la présente loi ou de toute autre loi.

[L.Y. 2002, ch. 186, art. 77]

PART 5
PUBLIC UTILITY COMPANIES

78 Application of this Part

This Part applies to all applications for incorporation of companies intended to operate or control any public or municipal franchise, undertaking, or utility, including water, gas, electric, and telephone companies, or that may require for its purposes the erection of any permanent structure in or on any highway, stream, or adjoining navigable waters, and to those companies when incorporated.

[S.Y. 2002, c. 186, s. 78]

79 Incorporation requirements

With the application for incorporation the applicants shall file with the registrar and produce to the Minister

(a) evidence that the proposed capital is sufficient to carry out the objects for which the company is to be incorporated, that the capital has been subscribed or underwritten and that the applicants are likely to command public trust and confidence in the undertaking;

(b) a detailed description of the plant, works, and intended operations of the company, and an estimate of their cost;

(c) a bylaw of every municipality in which the operations of the company are to be carried on authorizing the execution thereof in the manner set out in the detailed description above referred to;

(d) if the undertaking is to be carried on in an unorganized district a letter from the Minister approving of the undertaking; and

(e) if it is proposed that the company shall acquire any plant, works, land, undertaking, good will, contract, or other property or assets, a detailed statement of the nature and value thereof.

[S.Y. 2002, c. 186, s. 79]

PARTIE 5
SOCIÉTÉS DE SERVICE PUBLIC

78 Champ d'application de la présente partie

La présente partie s'applique aux demandes de constitution en personne morale de sociétés destinées à exploiter ou à régir un agrément public ou municipal, une entreprise ou un service public y compris d'eau, de gaz, d'électricité et de téléphone, ou qui peut requérir à ces fins l'érection d'une construction permanente sur ou au-dessus d'une route, d'un ruisseau ou d'un cours d'eau navigable, ainsi qu'à ces sociétés une fois constituées.

[L.Y. 2002, ch. 186, art. 78]

79 Dispositions obligatoires

Les requérants annexent à leur demande de constitution en personne morale déposée auprès du registraire et expédiée au ministre :

a) la preuve que le capital proposé est suffisant pour mener à bien les objectifs pour lesquels la société sera constituée en personne morale, que ce capital a été souscrit ou garanti et que les requérants recevront vraisemblablement l'appui et la confiance du public dans l'entreprise;

b) une description détaillée de l'usine, des ouvrages et des activités projetées de la société et une estimation de leur coût;

c) un règlement municipal de chaque municipalité sur le territoire de laquelle les activités de la société seront menées autorisant celles-ci, ces activités devant être menées conformément à la description mentionnée ci-dessus;

d) si l'entreprise doit être menée dans un territoire non organisé, une lettre du ministre l'approuvant;

e) s'il est projeté que la société se portera acquéreur de toute usine, ouvrage, bien-fonds, entreprise, achalandage, contrat ou autre bien ou élément d'actif, une description détaillée de leur nature et de leur valeur.

[L.Y. 2002, ch. 186, art. 79]

80 Reference to engineers or other experts

(1) The Minister may refer the application and all statements, evidence, and material filed thereon to engineers, architects, valuators, or other experts for consideration, investigation, and report regarding the public necessity for the undertaking of the company, the amount of capital required therefor, the value of any plant, works, lands, undertaking, good will, contract, or other property or assets to be acquired by the company and any other matter that may appear to be in the public interest regarding the undertaking.

(2) For the purposes of this Part, "**registrar**" means the registrar as defined in the *Business Corporations Act*.

[S.Y. 2002, c. 186, s. 80]

80 Renvoi à des ingénieurs ou autres experts

(1) Le ministre peut renvoyer la demande et les documents annexés à des experts — ingénieurs, architectes, évaluateurs ou autres — pour enquête et rapport concernant la nécessité de l'entreprise, le montant du capital requis, la valeur des usines, ouvrages, biens-fonds, entreprises, achalandages, contrats ou autres biens ou éléments d'actif à acquérir par la société et sur tout autre point qui peut sembler concerner l'intérêt public en ce qui touche l'entreprise.

(2) Pour l'application de la présente partie, « **registraire** » vise le registraire selon la définition que donne de ce mot la *Loi sur les sociétés par actions*.

[L.Y. 2002, ch. 186, art. 80]

81 Incorporation of public utility companies

The incorporation of any company hereafter formed for the purpose of operating any public utility under this Part, either solely or in conjunction with other objects, shall be by articles of incorporation under Part 2 of the *Business Corporations Act*.

[S.Y. 2002, c. 186, s. 81]

81 Constitution en personne morale

La constitution en personne morale d'une société formée en vue d'exploiter un service public sous le régime de la présente partie, que ce soit ou non avec d'autres objets, s'effectue par statuts constitutifs sous le régime de la partie 2 de la *Loi sur les sociétés par actions*.

[L.Y. 2002, ch. 186, art. 81]

82 Existing companies

The provisions of this Part continue to apply to any company formed by letters patent or by memorandum of association under Part II of the *Companies Act*.

[S.Y. 2002, c. 186, s. 82]

82 Sociétés existantes

Les dispositions de la présente partie continuent à s'appliquer à toute société formée par lettres patentes ou par acte constitutif sous le régime de la partie II de la *Loi sur les compagnies*.

[L.Y. 2002, ch. 186, art. 82]

83 Power to pass bylaws

The company may pass bylaws regarding the control and management of its undertakings, its dealings with the public it is incorporated to serve, and the setting and collection of tolls, charges, rates, or levies for the public service given by the company, except that no such bylaws shall have any force or effect or be acted on until approved by the Minister and, in the case of bylaws affecting its dealings with the public, the setting and collection of tolls, charges, rates, or levies for the public service given by the company, published twice in a public newspaper at the place where the undertaking of the company is carried on or as near thereto as may be and in the *Yukon Gazette*.

[S.Y. 2002, c. 186, s. 83]

83 Adoption de règlements administratifs

La société peut adopter des règlements administratifs concernant la régie et la gestion de son entreprise, ses rapports avec le public et la fixation et la perception de droits ou de taux pour son service public; cependant, ces règlements n'ont aucune validité tant qu'ils n'ont pas été approuvés par le ministre et, dans le cas de règlements visant les rapports avec le public, la fixation et la perception de droits et de taux, avant d'avoir été publiés deux fois dans un journal publié à l'endroit où l'entreprise est exploitée ou le plus près possible de cet endroit et dans la *Gazette du Yukon*.

[L.Y. 2002, ch. 186, art. 83]

84 Annual report

In addition to other returns that may be required by this or any other Act, the company shall on or before March 1 in each year make a report to the registrar under oath of the president and secretary, which shall specify,

(a) the cost of work, plant, and undertaking of the company;

(b) the amount of its capital, and the amount paid thereon;

(c) the amount received during the year from tolls, levies, rates, and charges and all other sources, stating each separately;

(d) the amount and rate of dividends paid;

(e) the amount expended for repairs; and

(f) a detailed description of any extension or improvement of the works or of any new works proposed to be undertaken in the current year, together with an estimate of the cost thereof.

[S.Y. 2002, c. 186, s. 84]

84 Rapport annuel

En plus des autres rapports que peuvent exiger la présente loi ou toute autre loi, la société doit, au plus tard le 1er mars, remettre un rapport au registraire accompagné du serment du président et du secrétaire; le rapport mentionne :

a) le coût de l'ouvrage, de l'usine et de l'entreprise de la société;

b) le montant de son capital et les montants libérés;

c) les montants reçus durant l'année des taux et autres droits ainsi que de toute autre source, les indiquant individuellement;

d) le montant et taux des dividendes versés;

e) le montant des réparations;

f) un état détaillé des agrandissements ou améliorations des ouvrages ou de tout projet d'ouvrage à entreprendre dans l'exercice en cours avec une estimation de leurs coûts.

[L.Y. 2002, ch. 186, art. 84]

85 Books open to inspection

The books of account of the company shall be at all reasonable times open to the inspection and examination of any shareholder.

[S.Y. 2002, c. 186, s. 85]

85 Accès aux livres

Les livres comptables de la société sont mis à la disposition des actionnaires pour consultation à toute heure convenable.

[L.Y. 2002, ch. 186, art. 85]

86 Appointment of inspector

If the Minister has any doubts as to the correctness or truth of any statements furnished by the company, the Minister may appoint a person to inspect and examine those books, and every person so appointed may take copies or extracts from them, and may require and receive from the keeper of the books, and also from the president and each of the directors of the company, and all other officers and servants thereof, all information as to the books and the affairs of the company generally, that the person so appointed considers necessary for the full and satisfactory investigation into and report on the state of affairs of the company, so as to enable them to determine the correctness of statements furnished by the company.

[S.Y. 2012, c. 14, s. 26] [S.Y. 2002, c. 186, s. 86]

86 Nomination d'un inspecteur

S'il a des doutes quant à l'exactitude ou à la véracité des déclarations de la société, le ministre peut nommer une personne chargée d'inspecter ces livres; celle-ci peut en prendre des copies ou des extraits et exiger et recevoir des préposés à leur garde et du président et de chacun des administrateurs de la société, ainsi que de son personnel, les renseignements concernant les livres ainsi que les affaires de la société de façon générale, qu'elle estime nécessaires à la conduite d'une enquête complète et à l'établissement d'un rapport sur les affaires de la société qui lui permette d'établir l'exactitude des déclarations de la société.

[L.Y. 2002, ch. 186, art. 86]

87 Power to construct and operate works

(1) A company incorporated for any of the purposes to which this Part applies has, respectively, full power to construct, maintain, complete, and operate works and apparatus for the production, sale, and distribution of gas, water, electricity, or other products for the purpose of light, heat, or power or of operating a system of telephones, or for any other purpose that the company may be incorporated for, as the case may be, and may construct and operate them by any means through, under, along, or over streets, highways, and public places.

(2) The powers of a company under subsection (1) are subject to any agreement in respect thereof that shall be made between the company and the municipal corporation within whose jurisdiction they are situate, ratified by a bylaw of the council of the municipality, and the municipality may, by agreement ratified as aforesaid, contract with any such company for the purchase of water, gas, or electricity and for the purchase or renting of any apparatus connected with the production, sale, or distribution thereof for any number of years not in the first instance exceeding 10 years, and renew any such contract from time to time for any period not exceeding 10 years as the council desires.

(3) In the case of streets, highways, and public places not within the limits of any municipality, the right of any such gas, water, electric, or telephone company to make use of those streets, highways, or public places to the extent indicated in this Part shall be subject to any terms that may be imposed by the Minister on application first made by the company.

[S.Y. 2002, c. 186, s. 87]

87 Pouvoir de construire et d'exploiter des ouvrages

(1) Une société dotée de la personnalité morale pour l'un des objets visés par la présente partie peut construire, entretenir, compléter et exploiter les ouvrages et dépendances pour la production, la vente et la distribution de gaz, d'eau, d'électricité ou autre produit aux fins de l'éclairage, du chauffage ou de la distribution d'énergie ou en vue de l'exploitation d'un système de téléphone ou à toute autre fin pour laquelle elle peut être constituée; elle peut également les construire et les exploiter le long des routes, chemins publics et places publiques ou au-dessus ou au-dessous de ceux-ci.

(2) Les pouvoirs mentionnés au paragraphe (1) sont assujettis aux accords qui peuvent être conclus entre la société et la municipalité sur le territoire de laquelle elle est située et ratifiés par un règlement municipal de son conseil; cette municipalité peut, par accord ratifié, conclure des contrats avec la société pour l'achat d'eau, de gaz ou d'électricité et pour l'achat ou la location de tout équipement lié à leur production, à leur vente ou à leur distribution pour une période initiale, maximale de 10 ans, et les renouveler pour une période maximale de 10 ans, selon ce qu'il estime indiqué.

(3) Dans le cas des rues, routes, chemins et lieux publics qui ne se trouvent pas sur le territoire d'une municipalité, le droit de la société de gaz, d'eau, d'électricité ou de téléphone de les utiliser aux fins mentionnées dans la présente partie est assujetti aux conditions qui peuvent être imposées par le ministre lors de la première demande faite par la société.

[L.Y. 2002, ch. 186, art. 87]

88 Meters and fittings

Every such company may sell and dispose of gas meters and gas, water, and electric fittings of every description for the use of private and public houses or for any establishment, company, or corporation whatsoever, as well as coke, coal, tar, and all the products of their works, refuse, or residuum arising to be obtained from the materials used or necessary for the manufacture of gas or electricity, and every company may let out to hire gas meters and gas, water, and electric fittings of every kind and description at any rate and rents that may be agreed on between the consumers and tenants and the company.

[S.Y. 2002, c. 186, s. 88]

88 Compteurs et accessoires

Ces sociétés peuvent vendre et aliéner des compteurs à gaz et des accessoires pour gaz, eau et électricité de quelque sorte pour usage dans des immeubles résidentiels ou publics ou pour tout établissement ou personne morale, ainsi que du charbon, du goudron ainsi que tous les produits de leurs ouvrages, y compris les rejets ou résidus qui proviennent des matériaux utilisés dans le cadre de la fabrication de gaz ou d'électricité, et chaque société peut louer ces compteurs et accessoires au taux et moyennant le loyer qui peuvent être convenus entre les consommateurs et locataires et cette société.

[L.Y. 2002, ch. 186, art. 88]

89 Laying mains and wires on streets

Any such company may break up, dig, and trench and use so much and so many of the streets, squares, highways, lanes, and public places of the locality for supplying them with gas, water, electricity, or other product or service or either of them the company has been incorporated that are necessary for laying the mains and pipes to conduct the gas or water or for placing the wires and connections to conduct the electricity or other product and to supply those services from the works of and by the company to and for the consumers or users thereof, doing no unnecessary damage in the premises and taking care as far as may be to preserve a free and uninterrupted passage through those streets, squares, highways, lanes, and public places while the works are in progress.

[S.Y. 2002, c. 186, s. 89]

89 Installation de canalisations

Ces sociétés peuvent creuser et utiliser la partie des rues, squares, chemins publics, allées et lieux publics de la localité en vue, d'une part, de fournir du gaz, de l'eau, de l'électricité ou tout autre produit ou service, ou les deux, pour lequel elles ont été constituées, travaux nécessaires à l'installation de conduites de gaz ou d'eau ou des fils électriques pour les installations de transport d'autres produits et, d'autre part, d'offrir ces services aux consommateurs et utilisateurs sans causer de dommage inutile aux lieux et en prenant les mesures voulues pour y préserver un passage libre et ininterrompu durant les travaux.

[L.Y. 2002, ch. 186, art. 89]

90 Company's rights regarding mains and pipes

(1) When any such company has laid down mains, pipes, wires, or conductors for the supply of gas, water, or electricity through any of the streets, squares, or public places of any locality, no other person or body politic or corporate shall, without the prior consent of the company nor otherwise than on payment to the company of any compensation that may be agreed on, or in default of agreement being arrived at, settled by arbitration, lay down any pipe, wire, or conductor for the supply of gas, water, or electricity within six feet of the company's main pipes, wires, or conductors or if it be impracticable to cut drains for those other main pipes, wires, or conductors

90 Droits de la société relativement aux canalisations

(1) Lorsqu'une société a installé des canalisations, des conduites, des fils ou des conducteurs pour la fourniture de gaz, d'eau ou d'électricité sous les rues, squares ou lieux publics d'une localité, il est interdit à quiconque, sans le consentement de la société ni autrement que sur paiement à celle-ci de la compensation qui peut être acceptée ou, à défaut d'entente, qui peut être fixée par arbitrage, d'installer toute canalisation, fil ou conducteur à ces fins dans les six pieds des installations de la société ou, s'il est impossible de couper les drains pour ces autres canalisations, fils ou conducteurs, à une distance plus grande, mais aussi proche de six pieds que les

at a greater distance then as nearly six feet as the circumstances of the case will admit.

(2) This section applies to mains, pipes, wires, or conductors crossing as well as running or parallel with other mains, pipes, wires, or conductors.

[S.Y. 2002, c. 186, s. 90]

91 Parts of buildings having different owners or tenants

When there are buildings in the locality the different parts whereof belong to different proprietors or are in possession of different tenants or lessees, the company may carry pipes, wires, or conductors to any part of any building so situate passing over the property of one or more proprietors or in the possession of one or more tenants to convey the gas, water, or electricity to the property of another or in the possession of another, and those pipes, wires, or conductors shall be carried up and attached to the outside of the building.

[S.Y. 2002, c. 186, s. 91]

92 Breaking up of passages

The company may also break up and uplift all passages common to neighbouring proprietors or tenants and dig or cut trenches therein for the purpose of laying down pipes, wires, or conductors or taking up or repairing them, doing as little damage as may be in the execution of the powers granted by this Part.

[S.Y. 2002, c. 186, s. 92]

93 Compensation

(1) Every company shall make satisfaction to the owners or proprietors of buildings or other property or to the public for all damages by them sustained in or by the execution of all or any of the powers referred to in this Part, subject to which provisions this Part shall be sufficient to indemnify every such company and their servants, and those by them employed for what they or any of them do in pursuance of the powers hereby granted.

(2) Every person claiming compensation from the company under this section shall proceed by originating summons.

[S.Y. 2002, c. 186, s. 93]

circonstances le permettent.

(2) Le présent article s'applique aux canalisations, conduites, fils ou conducteurs franchissant d'autres canalisations, conduites, fils ou conducteurs ou qui y sont parallèles.

[L.Y. 2002, ch. 186, art. 90]

91 Parties de bâtiments ayant différents propriétaires ou locataires

S'il y a des bâtiments dans la localité dont les parties appartiennent à différents propriétaires ou sont en la possession de différents locataires, la société peut installer les canalisations, conduites, fils ou conducteurs à travers toute partie de ces bâtiments et franchir la propriété de ces propriétaires ou celle qui est en la possession d'un ou plusieurs locataires pour acheminer le gaz, l'eau ou l'électricité vers la propriété d'un autre; ces canalisations, conduites, fils ou conducteurs devant être fixés à l'extérieur du bâtiment.

[L.Y. 2002, ch. 186, art. 91]

92 Rupture de passages

La société peut également couper et soulever les passages communs à des propriétaires ou locataires avoisinants et y creuser des tranchées aux fins d'y installer des canalisations, fils ou conducteurs, ou de les entretenir, en prenant soin de causer aussi peu de dommages qu'il est possible dans l'exécution des pouvoirs conférés par la présente partie.

[L.Y. 2002, ch. 186, art. 92]

93 Indemnisation

(1) Les sociétés sont tenues d'indemniser les propriétaires de bâtiments ou d'autres biens et le public pour les dommages subis à l'occasion de l'exécution de leurs pouvoirs; le cas échéant, la présente loi leur confère l'immunité, ainsi qu'à leurs employés, pour ce qui est accompli dans le cadre de ces pouvoirs.

(2) Quiconque réclame une indemnité à une société sous le régime du présent article est tenu de procéder par avis introductif.

[L.Y. 2002, ch. 186, art. 93]

94 Public safety

Every such company shall construct, locate, and operate its gas works, water works, or electric or telephone system and all apparatus and appurtenances thereto belonging or appertaining or therewith connected and wheresoever situated so as not to endanger the public health or safety.

[S.Y. 2002, c. 186, s. 94]

94 Sécurité publique

Ces sociétés doivent ériger et placer leurs ouvrages de gaz, d'eau ou d'électricité ou de téléphone ainsi que les appareils et accessoires liés à ceux-ci de façon à ne pas mettre en danger la sécurité ou la santé du public.

[L.Y. 2002, ch. 186, art. 94]

95 Limitation of powers of company

Nothing in this Part authorizes any such company or any person acting under the authority of it to take, use, or injure for the purposes of the company any house or other building or any land used or set apart as a garden, orchard, yard, park, paddock, plantation, planted walk, or avenue to a house, or nursery ground for trees, or to convey from the premises of any person any water already appropriated and necessary for their domestic uses without the prior consent in writing of the owner.

[S.Y. 2002, c. 186, s. 95]

95 Restriction aux pouvoirs des sociétés

La présente partie n'a pas pour effet d'autoriser ces sociétés ou les personnes qui agissent pour leur compte à prendre, à utiliser ou à endommager, pour l'accomplissement de leurs objets, toute maison ou autre bâtiment ou terrain utilisé comme jardin, verger, parc, plantation, promenade ou allée conduisant à une maison ou à une pépinière ou pour transporter des lieux de toute personne de l'eau déjà affectée à ses besoins domestiques et nécessaires à ces fins sans le consentement écrit du propriétaire.

[L.Y. 2002, ch. 186, art. 95]

96 Privileges of other companies

Nothing in this Part authorizes any company established under it to interfere with or infringe on any exclusive privilege granted to any other company.

[S.Y. 2002, c. 186, s. 96]

96 Privilèges des autres sociétés

La présente partie n'a pas pour effet d'autoriser une société constituée sous son régime à porter atteinte aux privilèges exclusifs accordés à une autre société.

[L.Y. 2002, ch. 186, art. 96]

97 Individual rights

Nothing in this Part prevents any person from constructing any works for the supply of gas, water, electricity, or telephones to their own premises, but any person supplying electricity, water, or telephone to any other premises than their own shall be subject to the provisions of this Part and shall pay the licence or fee at any time imposed on any other company or person supplying similar utilities in the same city, town, or district.

[S.Y. 2002, c. 186, s. 97]

97 Droits individuels

La présente partie n'a pas pour effet d'empêcher une personne de construire tout ouvrage pour la fourniture de gaz, d'eau, d'électricité ou d'un service téléphonique sur ses lieux propres, mais quiconque fournit de l'électricité, de l'eau ou un service téléphonique à tout autre lieu que le sien propre doit être assujetti à la présente partie et payer la licence ou les droits imposés à toute autre société ou personne qui offre un service public semblable dans la même ville, cité ou district.

[L.Y. 2002, ch. 186, art. 97]

98 Exemption from distress and seizure

Neither the service nor the connecting pipes, wires, or conductors of the company, nor any meters, lustres, lamps, pipes, gas fittings, electric fittings, or any other property of any kind whatsoever of the company shall be subject to or liable for rent nor liable to be seized or attached in any way by the possessor or owner of the premises wherein they may be, nor be in any way whatsoever liable to any person for the debt of any person to and for whose use or the use of whose house or building they may be supplied by the company despite the actual or apparent possession thereof by the person.

[S.Y. 2002, c. 186, s. 98]

98 Insaisissabilité

Ni le service, ni les canalisations, fils ou conducteurs d'une société ni les autres biens d'une société — compteurs, lampes, tuyaux, installations de gaz ou installations électriques — ne peuvent être saisis pour non-paiement de loyer par le possesseur ou le propriétaire des biens où ils se trouvent, ni répondre de la dette de toute personne à la maison ou aux bâtiments de laquelle ils peuvent être fournis par la société en dépit de toute possession réelle ou apparente de cette personne.

[L.Y. 2002, ch. 186, art. 98]

99 Nonpayment of rates, etc.

If any person supplied by the company with gas, water, electricity, or other product, telephone, or other service neglects to pay the rent, rate, or charge due to the company at any of the times set for the payment thereof, the company or anyone acting under its authority on giving 48 hours previous notice to the person supplied may stop the supply of gas, water, electricity, or other product from entering or being supplied, may cut off the telephone or other service to the premises of and to the person in arrears by cutting off the service pipe or pipes, wires, or conductors or by any other means that the company or its officers see fit, and may recover the rent or charge due up to that time together with the expense of cutting off the gas, water, electricity, or other product or service as the case may be, in any competent court despite any contract to furnish for a longer time.

[S.Y. 2002, c. 186, s. 99]

99 Non-paiement

Si une personne à qui une société fournit du gaz, de l'eau, de l'électricité ou tout autre produit, un service téléphonique ou autre omet de payer les loyers, taux ou droits dus à la société dans les délais prévus pour leur paiement, la société ou toute personne qui peut agir pour celle-ci peut, après lui avoir donné un préavis de 48 heures, interrompre la fourniture ou le service par les moyens qu'elle ou son personnel estime indiqués, y compris par débranchement des canalisations, des conduites, des fils ou des conducteurs; elle peut recouvrer ces arriérés et les frais liés à l'interruption du service devant tout tribunal compétent, en dépit de tout contrat prévoyant la fourniture pour une durée plus longue.

[L.Y. 2002, ch. 186, art. 99]

100 Entry of premises by employees of company

(1) In all cases where the company may lawfully cut off and take away the supply of gas, water, electricity, or other product or service from any house, building, or premises the company, their agents, or their workers on giving 48 hours previous notice to the person in charge or the occupier may enter into the house, building, or premises between the hours of nine o'clock in the forenoon and five o'clock in the afternoon, making as little disturbance and inconvenience as possible, and may remove and take away any pipe, meter, cock, branch, lamp, fitting, telephone, or other apparatus the property of and

100 Droit d'entrée du personnel

(1) Dans les cas où elle peut légalement interrompre la fourniture du service de gaz, d'eau, d'électricité ou de tout autre produit ou service d'une maison, d'un bâtiment ou d'un lieu, la société, ses mandataires ou ses travailleurs peuvent, sur préavis de 48 heures à la personne en charge ou à l'occupant des lieux, y pénétrer entre 9 h et 17 h et, avec le moins d'interruption ou d'inconvénient possible, retirer tout équipement lui appartenant.

belonging to the company.

(2) Any servant duly authorized by the company may between the hours referred to in subsection (1) enter any house into which gas, water, electricity, or other product or service have been taken or supplied for the purpose of repairing and making good any such house, building, or premises or for the purpose of examining any meter, pipe, apparatus, or fitting belonging to the company or used for their gas, water, electricity, or other product or service.

(3) If any person does not permit the servants and officers of the company to enter and perform the acts referred to in subsection (1) or (2), the person so refusing or obstructing shall incur a penalty to the company, for every such offence, of $20, and a further penalty of $4 for every day during which the refusal or obstruction continues.

[S.Y. 2002, c. 186, s. 100]

(2) Le personnel dûment autorisé par la société peut, durant ces heures, entrer dans toute maison où un service de gaz, d'eau ou d'électricité ou d'autre produit ou service a été offert afin de réparer cette maison, ce bâtiment ou ce lieu ou afin d'examiner tout compteur, canalisation, appareil ou installation appartenant à la société ou utilisé pour la fourniture de gaz, d'eau, d'électricité ou d'autre produit ou service.

(3) Quiconque ne permet pas au personnel de la société de pénétrer sur les lieux et d'accomplir les actions mentionnées aux paragraphes (1) et (2) est passible d'une amende de 20 $ payable à la société pour toute violation et de 4 $ pour toute journée pendant laquelle le refus ou l'obstruction continue.

[L.Y. 2002, ch. 186, art. 100]

101 Discontinuance of service

If any customer discontinues the use of the gas, or other means of lighting or heating, or water, electricity, or power or other product or service furnished or supplied by a company subject to the provisions of this Part, or the company lawfully refuses to continue any longer to supply it, the officers and servants of the company may at all reasonable times enter the premises in or on which the customer was supplied with gas, or other means of lighting or heating, water, electricity, power, or other product or service for the purpose of removing therefrom any fittings, machine, apparatus, meters, pipes, wires, conductors, telephones, or other things, being the property of the company, in or on the premises and may remove them therefrom, doing no unnecessary damage.

[S.Y. 2002, c. 186, s. 101]

101 Interruption du service

Si un client interrompt l'utilisation de gaz ou de tout autre moyen de chauffage ou d'électricité, ou cesse d'utiliser de l'eau, de l'électricité ou de l'énergie ou tout autre produit ou service fourni par une société assujettie à la présente partie ou que la société refuse légalement de continuer à les offrir, son personnel peut à toute heure convenable entrer sur les lieux où le service ou le bien était fourni afin d'y enlever, sans causer de dommages inutiles, les installations, appareils, canalisations, accessoires, conducteurs, téléphones et autres objets lui appartenant.

[L.Y. 2002, ch. 186, art. 101]

102 Expropriation

(1) If it is deemed proper to conduct any of the pipes, wires, or conductors or to carry any of the works of the company through the lands of any person lying within or without 10 miles of the locality for supplying which the company is incorporated and the consent of the person cannot be obtained for that purpose, the company may take or use the land required and nominate and appoint a disinterested person and the owner or owners of the land taken or damaged may nominate and appoint a third person and those three

102 Expropriation

(1) S'il est réputé indiqué de faire passer des canalisations, fils ou conducteurs ou de mener des travaux à travers le bien-fonds d'une personne, s'ils sont situés à moins ou à plus de 10 milles de la localité pour l'approvisionnement de laquelle la société a été constituée en personne morale, et que le consentement de cette personne ne peut être obtenu à cette fin, la société peut prendre et utiliser le bien-fonds requis et nommer toute personne désintéressée, et le propriétaire du terrain en cause peut nommer une

persons shall act as arbitrators in the matter between the company and the owner or owners of the property.

(2) Nothing in this section authorizes the company to take or use any house, land, or property in contravention of section 94.

[S.Y. 2002, c. 186, s. 102]

tierce personne, et ces trois personnes agissent à titre d'arbitres entre la société et le propriétaire.

(2) Le présent article n'a pas pour effet d'autoriser la société à prendre ou à utiliser une maison, un bien-fonds ou des biens contrairement à l'article 94.

[L.Y. 2002, ch. 186, art. 102]

103 Powers and duties of arbitrators

The arbitrators shall examine all witnesses and administer all necessary oaths or declarations to them, and the arbitrators or a majority of them shall award, determine, and adjudge what sum or sums of money respectively shall be paid to the owner or owners of the property so taken or damaged by the company.

[S.Y. 2002, c. 186, s. 103]

103 Attributions des arbitres

Les arbitres interrogent les témoins et font prêter les serments ou passer les déclarations nécessaires, et eux-mêmes ou une majorité d'entre eux déterminent la somme d'argent destinée à indemniser le ou les propriétaires en cause.

[L.Y. 2002, ch. 186, art. 103]

104 Payment of award

The sum or sums of money so awarded shall be paid within three months after the date of the award and in default of the payment the owner or owners may resume the possession of the property with all the rights appertaining thereto, but the company shall be held liable to the owner for any damage it may have done to the property.

[S.Y. 2002, c. 186, s. 104]

104 Paiement de l'indemnité

L'indemnité attribuée par les arbitres doit être payée dans les trois mois après la date de la sentence, et, à défaut, le ou les propriétaires peuvent reprendre possession du bien avec tous les droits y afférents, mais la société peut être tenue pour responsable envers eux de tout dommage causé au bien.

[L.Y. 2002, ch. 186, art. 104]

105 Failure to appoint arbitrator

In the event of the company or the owner of the property failing to appoint an arbitrator after eight days notice from one of the parties to the other or of the two arbitrators failing to appoint a third, a judge of the Supreme Court may appoint a third arbitrator and the decision of the three arbitrators or a majority of them shall be binding on all parties concerned.

[S.Y. 2002, c. 186, s. 105]

105 Défaut de nommer un arbitre

Si la société ou le propriétaire du bien ne nomme pas un arbitre dans les huit jours d'un avis à l'une ou l'autre partie ou si les deux arbitres omettent d'en nommer un troisième, un juge de la Cour suprême peut nommer le troisième arbitre, et la décision des trois arbitres ou d'une majorité d'entre eux lie les parties concernées.

[L.Y. 2002, ch. 186, art. 105]

106 Duty of company to supply utility service

All companies having the privileges conferred by this Part shall supply the utility controlled by them to all persons within the area covered by the privilege except in those cases where the company may lawfully refuse to supply the utility.

[S.Y. 2002, c. 186, s. 106]

106 Obligation des sociétés

Les sociétés disposant des privilèges conférés par la présente partie sont tenues de fournir le service public qu'elles contrôlent à toutes les personnes se trouvant dans la zone visée, sauf si elles peuvent légalement refuser de le faire.

[L.Y. 2002, ch. 186, art. 106]

TAB 12

In the Court of Appeal of Alberta

Citation: ATCO Electric Ltd v Alberta Utilities Commission, 2023 ABCA 129

Date: 20230414
Docket: 1901-0344AC
Registry: Calgary

2023 ABCA 129 (CanLII)

Between:

ATCO Electric Ltd.

Appellant

- and -

Alberta Utilities Commission

Respondent

- and -

AltaLink Management Ltd. in its capacity as general partner of AltaLink L.P.

Intervenor

The Court:

The Honourable Justice Jack Watson
The Honourable Justice Frans Slatter
The Honourable Justice Anne Kirker

Memorandum of Judgment

Appeal from the Decision of the
Alberta Utilities Commission
Dated the 2nd day of October, 2019
Decision 21609-D01-2019

Memorandum of Judgment

The Court:

[1] The appellant appeals a decision of the Alberta Utilities Commission which denied the appellant the ability to recover some of the costs it suffered as a result of the Fort McMurray wildfire, because the Commission would not permit the appellant to include those costs in its prudently incurred costs and expenses when setting its rates: *ATCO Electric Ltd., Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire*, decision #21609-D01-2019, 2019 LNAUC 170.

Facts

[2] The Commission sets tariffs under the *Electric Utilities Act*, SA 2003, c. E-5.1 on a "performance-based regulation plan". The system, however, recognizes adjustments for "Z factors" to account for the recovery of unanticipated but prudently incurred costs resulting from exogenous events:

> A Z factor is ordinarily included in a PBR [performance-based regulation] plan to provide for exogenous events. The Z factor allows for an adjustment to a company's rates to account for a significant financial impact (either positive or negative) of an event outside of the control of the company and for which the company has no other reasonable opportunity to recover the costs within the PBR formula.

While the Z factors are designed to account for material impacts on otherwise prudently incurred costs from causes outside the control of the utility, not all prudently incurred costs will necessarily be recoverable: reasons at paras. 3, 11, 26.

[3] There are five criteria for Z factor treatment:

(a) The impact must be attributable to some event outside management's control.

(b) The impact of the event must be material. It must have a significant influence on the operation of the company otherwise the impact should be expensed or recognized as income, in the normal course of business.

(c) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.

(d) All costs claimed as an exogenous adjustment must be prudently incurred.

(e) The impact of the event was unforeseen.

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[4] In 2016 a number of wildfires spread through Northern Alberta. Of particular note was the Fort McMurray wildfire, also called the Regional Municipality of Wood Buffalo wildfire, which was unprecedented in its scope and duration. A great deal of property was destroyed, including property used by the appellant to distribute electrical services in the Regional Municipality of Wood Buffalo. That destroyed equipment was removed and replaced as required. Some of the appellant's fire losses were covered by insurance, and the appellant applied for a Z Factor adjustment to its tariff to recover the balance of the loss.

[5] The insurance available did not extend to the assets destroyed by the wildfires that are the subject of this appeal. The Commission had previously accepted that the premiums and deductibles for that insurance were too high: *ATCO Electric Ltd., 2007-2008 General Tariff Application,* AUC Decision 2007-071 at p. 118. The customers were paying the premiums, and an analysis over the previous eight years showed that the premiums exceeded the recovered losses. It was therefore prudent to self-insure such potential losses.

[6] When the appellant applied for a Z Factor adjustment because of the costs related to the Fort McMurry wildfire, the Commission directed that it also address the issue of the undepreciated capital cost (or net book value) of the assets destroyed by the fire. These assets or costs were said to be "stranded" by the wildfire. In the decision under appeal, the Commission allowed recovery of some of the costs arising from the wildfire but did not allow the appellant to continue to recover from its customers the remaining net book value of the assets destroyed in the wildfire. The reasonable opportunity previously given to recover those prudent costs was rescinded. In other words, as a result of the wildfire the Commission actually removed from the calculation of tariffs expenses that had previously been accepted as having been prudently incurred.

[7] In order to properly frame the issue, it is helpful to summarize the way depreciable assets are dealt with when setting utility tariffs. The Commission helpfully summarized the approach in its factum:

> 9. Utilities in Alberta do not depreciate assets on an individual, asset-by-asset basis. Instead, similar assets that are expected to have a similar service life are grouped into mass property accounts.[1] Not all assets in a mass property account will retire at the same time, and it is not possible to know in advance which individual assets in a mass property account will have short service lives, and which will have long lives. However, statistical analysis of actual retirements is used to model a survivor curve that predicts which portion of the group will survive to each age, and forecast the average service life for the group.

[1] The Commission gives the example of a mass property account for distribution poles which are given an expected average service life.

> 10. When an individual asset is retired, it is assumed that it is one of the assets within the mass property account that was contemplated (in the survivor curve) to retire in that particular year. No gain or loss is booked on retirement, because each retired asset is assumed to have been fully depreciated (and therefore assumed to have no net book value) at the time of its retirement.
>
> 11. In its "Utility Asset Disposition" decision[2] (UAD Decision), the Commission drew a distinction between ordinary retirements and extraordinary retirements. If an asset is retired from service before it has reached the end of its useful life, that retirement is assessed to determine whether it is an ordinary or extraordinary retirement.
>
> 12. The removal of an asset is considered to be an ordinary retirement if the cause or events surrounding the retirement was something reasonably assumed to have been anticipated or contemplated in the determination of the depreciation parameters (i.e. the survivor curve and average service life) that informed the depreciation or amortization provisions for the relevant mass property account.
>
> 13. The removal of an asset is considered to be an extraordinary retirement if the characteristics of the event under which the asset was removed from service have not been taken into account in the depreciation parameters.
>
> 14. Ratepayers are accountable for the net book value of an asset taken out of service as a result of an ordinary retirement, because the type of retirement is factored into the determination of the average service life of the applicable class of assets. Utility shareholders are accountable for the net book value of an asset taken out of service as a result of an extraordinary retirement because the utility is the sole property owner of the asset.

The base approach is therefore that the utility will account for depreciation in its annual tariffs based on the average depreciation derived from the "survivor curve" of each mass property account. In other words, no depreciation or cost is accounted for in any one year based on the survival or retirement of any particular asset.

[8] If no adjustments were made to the system, when an asset was destroyed while in service (for example, as the result of a wildfire) its treatment for depreciation purposes would not change. No loss would be recorded in the year of destruction. Subject to an adjustment for insurance proceeds (if any), the remaining value of that asset would stay in the mass property account and would be depreciated in future years based on the average survival curve for all other assets in that mass property account. At the same time, new assets acquired to replace the destroyed assets would

[2] Cited and discussed *infra*, paras. 11, 28-30.

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be added into the mass property account. As a result, in future years the amount of depreciation charged for that mass depreciation account would increase, because it would reflect the remaining net book value of the destroyed assets as well as the cost of the replacement assets. At the end of the day, the utility would eventually recover the prudent costs of the original destroyed assets and the replacement assets.

[9] Central to this appeal is the way the Commission deals with "extraordinary retirements" as summarized in paras. 13-14 of its factum: see *supra*, para. 7. If the removal of the asset from service was caused by an event which was considered in the original calculation of the survival curve then the retirement is considered to be "ordinary". The utility can keep the remaining net book value of that asset in the mass depreciation account and recover it through depreciation in future years. However, if the removal of the asset from service was caused by an event which was not considered in the original calculation of the survival curve then the retirement is considered to be "extraordinary". In that event the utility is not allowed to keep the remaining net book value of that destroyed asset in the mass depreciation account. The result is that the utility is never able to recover the cost of that destroyed asset, even though its original purchase was prudent and necessary for the provision of the utility service to customers.

[10] To summarize, the effect of the decision under appeal was to disrupt the normal cycle of depreciation, because the loss of assets resulting from the Fort McMurray wildfire was said to be "extraordinary". The full cost of those destroyed assets in the pool would previously have been recovered over their expected average life, notwithstanding how long any particular asset actually survived, even if its life had been cut short by forces of nature. Because the Fort McMurray wildfire losses were more significant than those predicted in the survival curves and so were said to be extraordinary, the decision under appeal changed the approach by now looking at individual asset survival history. Further, any destruction by fire of an individual asset in a mass depreciation pool meant that the remaining undepreciated capital cost of that asset had to be removed from the pool. The appellant would no longer be able to recover those costs.

[11] As noted, even though new costs arising from the Fort McMurray wildfire were allowed as Z Factor adjustments, as a result of that same fire the decision under appeal actually denied some previously approved expenses. The Commission followed principles it extracted from ***ATCO Gas & Pipelines Ltd v Alberta (Energy & Utilities Board)***, 2006 SCC 4, [2006] 1 SCR 140 (the ***Stores Block*** decision) and its decision *Re Utilities Asset Disposition*, #2013-417, 2013 LNAUC 406, which was affirmed by ***FortisAlberta Inc v Alberta (Utilities Commission)***, 2015 ABCA 295, 28 Alta LR (6th) 252, leave to appeal refused [2016] 1 SCR ix. As noted, the Commission proceeded on the basis that "ordinary retirements" of depreciable assets are for the account of customers, but "extraordinary retirements" are for the account of the shareholders: reasons at paras. 89, 104.

[12] The Commission summarized its position:

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> 104 . . . Further, these property and corporate law principles [set out in *Stores Block* and *FortisAlberta*] symmetrically allocate to the utility the benefits and risks of property ownership. A literal application of these fundamental principles, as subsequently directed by the courts, would allocate all benefits and risks to the utility shareholder in a symmetrical manner with the shareholder retaining all gains on sale and any benefits from the redeployment of utility property for non-utility purposes as well as absorbing any losses on sale and the costs of any unrecovered capital associated with assets that cease to be used or required to be used in providing utility service. Any gain or risk of loss with respect to the utility's original investment would be for the account of the owner of the property in a symmetrical manner consistent with the principles of property ownership and corporate law. . . .
>
> 111. Having found that traditional depreciation methods accorded with the legislation and the *Stores Block* line of decisions, the Commission in the UAD decision summarized the applicable principles at paragraph 327 of that decision, quoted at paragraph 89 above. The Commission confirmed that rate base and, therefore, customer rates should not include costs associated with assets that are subject to an extraordinary retirement. Such assets include obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes, property that should be removed because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or unexpected and permanent shutdown of an entire operating assembly or plant. These types of assets must be retired (removed from rate base) and moved to a non-utility account because they have become no longer used or required to be used as the result of causes that were not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions approved by the Commission.

After a fact specific analysis, the Commission concluded that the property losses from the Fort McMurray wildfires were extraordinary retirements: reasons at para. 127. As a result "the remaining net book value of the destroyed assets associated with the [Fort McMurray] wildfire must be for the account of the ATCO Electric shareholders": reasons at para. 128. The appellant was directed to remove the remaining net book value of those assets from the applicable mass property accounts.

[13] The Commission concluded its treatment of the wildfire losses resulted in just and reasonable rates, although without a detailed analysis of the provisions in the *Electric Utilities Act*:

> 130 The Commission's finding that costs of the retirement event should be allocated to shareholders results in just and reasonable rates. This finding is consistent with the governing legislation, the fundamental property and corporate

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> law principles established by the courts and the guidance of the courts on the allocation of risk and benefits associated with property ownership. This guidance was reviewed by the Commission in the UAD decision and subsequently upheld on appeal. The guidance limits the Commission's flexibility in dealing with cost allocation upon the retirement of utility assets, both those reasonably anticipated and those that are unanticipated. . . .

The Commission accordingly read the ***Stores Block*** and ***FortisAlberta*** decisions as "limiting its flexibility" in dealing with destroyed assets.

[14] The appellant was given permission to appeal the decision of the Commission on two issues:

(a) Did the Commission err in law by fettering its discretion regarding the recovery of the prudent costs of the assets destroyed by the wildfires?

(b) Did the Commission err in its interpretation of the *Electric Utilities Act* by incorporating inapplicable concepts from gas utility legislation or by disregarding provisions that require ATCO be provided a reasonable opportunity to recover the prudent costs and investments it had incurred to provide safe and reliable service to customers?

Standard of Review

[15] Section 29 of the *Alberta Utilities Commission Act*, SA 2007, c. A-37.2 provides an avenue of appeal from decisions of the Commission on a question of law or jurisdiction[3] if permission to appeal is granted. The standard of review in statutory administrative appeals is the standard applied in ordinary civil appeals: ***Minister of Citizenship and Immigration v Vavilov***, 2019 SCC 65 at para. 36, [2019] 4 SCR 653. Since appeals from the Commission are only possible on questions of law, the standard of review in this appeal is correctness. Deference is no longer extended to the Commission's decisions on points of law.

[16] As the concurring reasons in ***Vavilov*** point out at para. 245, it is unlikely that the Legislature had the standard of review in mind when it replaced common law judicial review of regulatory tribunals with judicial review via statutory appeals. This was merely a choice of procedure and the reviewing forum. One thing is clear: by enacting a statutory appeal route the

[3] All jurisdictional errors are errors of law. Reference to "law or jurisdiction" in the statute is merely a historical anomaly: ***JH Drilling Inc v Alberta (Natural Resources Conservation Board)***, 2014 ABCA 378 at para. 15. Since there is no longer any presumptive difference in the standard of review the distinction is usually of no importance.

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Legislature did not intend that the Court would take over the management of the electrical distribution and transmission system in Alberta. As noted in ***FortisAlberta*** at para. 172:

> 172 One must also bear in mind that the questions raised have political and economic aspects. Courts are poorly positioned to opine on such matters. Judicial review considers the scope or breadth of jurisdiction, but by legislative design the selection of a policy choice from among a range of options lies with the Commission empowered and mandated to make that selection.

This means that while appeals can be taken on points of law, the Court should not be quick to identify extricable questions of law in what are more properly categorized as mixed questions of fact and law, questions of policy, or matters of discretion: ***Teal Cedar Products Ltd. v British Columbia***, 2017 SCC 32, [2017] 1 SCR 688. Deference to the Commission and its expertise are still appropriate on many important issues, and its reasons are important input in the correctness review: ***Vavilov*** at para. 54; ***Planet Energy (Ontario) Corp. v Ontario Energy Board***, 2020 ONSC 598 at paras. 26, 31 (Div Ct).

[17] Another predictable effect of ***Vavilov*** is that it has the potential to destabilize some of the precedents of this Court in this important area of law: see ***Neptune Wellness Solutions v Canada (Border Services Agency, President)***, 2020 FCA 151 at para. 13. For example, in ***FortisAlberta*** this Court held that the standard of review of the Commission's legal decisions was reasonableness, even though a correctness standard of review had been used in ***Stores Block***. One premise of the reasonableness standard of review was that some legal issues were open to several interpretations, particularly having regard to policy and discretionary considerations. In the present appeal the appellant argues that ***FortisAlberta*** is no longer a binding precedent because the standard of review has changed.

[18] ***Vavilov*** should not be read as automatically displacing all the case law decided under the pre-***Vavilov*** standard of review regime. For one thing, even if a decision was reviewed for "reasonableness" and found to be reasonable, that does not mean that the reviewing court did not also agree that the decision was "correct": see for example ***FortisAlberta*** at paras. 130, 134, 137-38, 148. Further, decisions like ***FortisAlberta*** were themselves based on binding decisions like ***Stores Block***. If the tribunal decision in ***FortisAlberta*** had failed to follow binding precedent it would not have been reasonable. The importance of stability in the law means that after ***Vavilov*** binding precedents of this Court should presumptively be regarded as continuing to be binding, notwithstanding the change in the standard of review analysis: see ***Vavilov*** at paras. 18, 143-44.

Fettering of Discretion

[19] The Commission summarized its conclusion about the remaining net book value of the destroyed assets as follows:

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> 128. Accordingly, for regulatory purposes the RMWB [Regional Municipality of Wood Buffalo] wildfire gives rise to an extraordinary retirement of the destroyed assets. As a result of these findings, the principles established by *Stores Block* and the related Court of Appeal decisions dictate that the remaining net book value of the destroyed assets associated with the RMWB wildfire must be for the account of the ATCO Electric shareholders. ATCO Electric is directed, in the compliance filing to this decision, to provide all accounting entries reflecting the retirement of the assets destroyed by the RMWB wildfire. (Emphasis added)

The appellant argues that in this passage the Commission unlawfully fettered its discretion. The appellant points to other passages where the Commission signalled that it felt bound by the ***Stores Block*** decision, which drove its treatment of the remaining net book value of destroyed depreciable assets.

[20] Under the statute appeals are only available on points of law. The exercise of a discretion one way or the other will not generally amount to an error of law. Fettering can be an error of law, for example where the decision maker denies having any discretion. If a decision maker with a discretion states that it is compelled to reach a particular conclusion, regardless of the circumstances before it, that can amount to an error of law. Further, a decision maker with a discretion may err in law by considering irrelevant factors or disclaiming relevant factors.

[21] But to fetter a discretion, the decision maker must have a discretion. The Commission undoubtedly has discretionary powers in many areas, but obeying the law is not one of them. The Commission has no discretion to ignore the applicable statutes, or binding precedents of the Supreme Court of Canada or the Alberta Court of Appeal: ***FortisAlberta*** at paras. 76, 137, 161. When the Commission stated that the law "dictated" the outcome, that did not reflect any exercise of discretion. There is a difference between *stare decisis* and fettering of discretion. Subsequent comments by the Commission at paras. 130-31 confirm that it was just stating that it was bound by prior decisions of the Supreme Court of Canada and this Court. Whatever the law was, the Commission was compelled to follow it. If the Commission's impression of the law was erroneous, that is an error of law, but it is not a fettering of discretion.

[22] The issue on this appeal is therefore not whether the Commission fettered its discretion, but whether it correctly interpreted and applied the legal standards that governed in the circumstances.

The Jurisprudential Background

[23] Because the Decision of the Commission was heavily influenced by its interpretation of ***Stores Block*** (and other cases in that line of precedents) and ***FortisAlberta*** (which upheld *Re Utilities Asset Disposition*), an examination of what those decisions did and did not decide is important.

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[24] ***Stores Block*** arose when the utility applied to sell surplus assets that had previously been included in the rate base. The issue was whether the profit from that sale had to be shared with the customers of the utility. The Supreme Court of Canada reiterated the fundamental relationship between the shareholders of a privately owned utility and the customers of that utility. The shareholders are the beneficial owners of the assets of the utility, and are entitled to the profits from, and must bear the burden of any losses from the ownership of those assets. The customers "have access to the utility at a fair price -- nothing more": ***Stores Block*** at para. 63. The customers have no property rights in the assets of the utility.

[25] As a result, the utility's shareholders were entitled to keep the profits that resulted from the sale of the Stores Block land and buildings. While the ***Stores Block*** decision related to profits resulting from the sale of the assets, the reasons assumed that the shareholders would have to bear the burden of any corresponding losses related to those assets.

> 67. The fact that the utility is given the opportunity to make a profit on its services and a fair return on its investment in its assets should not and cannot stop the utility from benefiting from the profits which follow the sale of assets. Neither is the utility protected from losses incurred from the sale of assets. . . .

The ***Stores Block*** decision related to the sale of assets previously included in the rate base. It did not discuss losses due to the destruction of assets, for example by forces of nature, because none were involved.

[26] ***Stores Block*** discussed at para. 69 the distinction between the cost of depreciable assets that are included in the rate base, and gains or losses that might arise from the disposition of those assets:

> 69. . . . The Board misdirected itself by confusing the interests of the customers in obtaining safe and efficient utility service with an interest in the underlying assets owned only by the utility. While the utility has been compensated for the services provided, the customers have provided no compensation for receiving the benefits of the subject property. The argument that assets purchased are reflected in the rate base should not cloud the issue of determining who is the appropriate owner and risk bearer. Assets are indeed considered in rate setting, as a factor, and utilities cannot sell an asset used in the service to create a profit and thereby restrict the quality or increase the price of the service. Despite the consideration of utility assets in the rate-setting process, shareholders are the ones solely affected when the actual profits or losses of such a sale are realized; the utility absorbs losses and gains, increases or decreases in the value of assets, based on economic conditions and occasional unexpected technical difficulties, but continues to provide service both with regard to price and quality. There can be a default risk affecting ratepayers, but this does not make ratepayers residual claimants. . . . (Emphasis added)

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While ***Stores Block*** made these collateral comments about the removal of surplus assets from the rate base, it was not directly concerned with setting just and reasonable tariffs for the utility.

[27] Some of the key points from ***Stores Block*** are as follows:

(a) ***Stores Block*** was not about setting rates ("just and reasonable tariffs"), it was about profits from the sale of utility assets.

(b) When ***Stores Block*** raised the issue of "symmetry", it was referring to the fact that the utility shareholders were entitled to the profits from the sale of utility assets and were therefore subject to any losses from the sale or disposition of such assets. It referred to "actual profits or losses of such a sale" and "increases or decreases in the value of assets".

(c) While ***Stores Block*** made some imprecise collateral references to disposition of assets for reasons other than on sale ("economic conditions and occasional unexpected technical difficulties"), it did not contemplate losses like the fire losses that are involved in this appeal. Destruction of an asset by fire would not usually be described as a "decrease in value".

(d) While it made some reference to assets in the rate base, they were collateral to the main issue about the entitlement to the profits from the sale of utility assets. The Court was primarily explaining how inclusion of depreciable assets in the rate base did not involve any transfer of an ownership interest to the customers, even though the customers ended up paying for the assets as they were consumed.

(e) The references to the inclusion of assets in the rate base were to assets that were withdrawn from service because they were surplus to requirements. ***Stores Block*** did not deal with what would happen to destroyed assets that had been prudently acquired and previously included in the rate base when and because they were being used to provide utility services. In ***Stores Block*** it appears that there was no objection to the utility's proposal to recover the remaining net book value of the depreciable component of the Stores Block building from the sale proceeds.

[28] ***Stores Block*** was perceived to have displaced some previous assumptions about the regulation of utilities. The Commission held a hearing to consider its impact, which resulted in the Commission's decision *Re Utilities Asset Disposition*. Numerous stakeholders were invited to participate in this hearing, which was intended to develop a consistent approach to the principles set out in the ***Stores Block*** decision. *Re Utilities Asset Disposition* concluded that all "stranded assets", being assets that are not fully depreciated but which are no longer used for the provision of the utility service to the customers, must be removed from the rate base. Any gains or losses from removal of an asset from the rate base by an extraordinary event, including early obsolescence, advancement in technology, or destruction, were for the account of the shareholders,

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not the customers. This applied equally to dispositions outside the ordinary course of business, such as those resulting from forces of nature.

[29] *Re Utilities Asset Disposition* was a generic, policy-based decision. It did not consider any particular expense, loss, or specific incident of stranding, or determine whether any particular tariff was just and reasonable. The Commission saw it as embracing a "literal" interpretation of ***Stores Block***:

> 104. . . . A literal application of these fundamental principles, as subsequently directed by the courts, would allocate all benefits and risks to the utility shareholder in a symmetrical manner with the shareholder retaining all gains on sale and any benefits from the redeployment of utility property for non-utility purposes as well as absorbing any losses on sale and the costs of any unrecovered capital associated with assets that cease to be used or required to be used in providing utility service.

This passage refers to "gains on sale and any benefits from the redeployment" of property, which it contrasted with "absorbing any losses on sale and the cost of any unrecovered capital".

[30] The decision, however, then extrapolated this literal interpretation to any other type of loss. As the Commission noted:

> 111. . . . customer rates should not include costs associated with assets that are subject to an extraordinary retirement. Such assets include obsolete property, property to be abandoned, overdeveloped property and more facilities than necessary for future needs, property used for non-utility purposes, property that should be removed because of circumstances including unusual casualties (fire, storm, flood, etc.), sudden and complete obsolescence, or unexpected and permanent shutdown of an entire operating assembly or plant. These types of assets must be retired (removed from rate base) and moved to a non-utility account because they have become no longer used or required to be used as the result of causes that were not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions approved by the Commission. (Emphasis added)

Re Utilities Asset Disposition therefore extended the literal interpretation of ***Stores Block*** to all "extraordinary retirements", not just those related to the sale of assets. It now specifically covered assets lost due to forces of nature that were previously properly in the rate base. Going forward such assets "must be retired (removed from rate base)", which meant that prudently incurred past expenses would effectively become unrecoverable.

[31] *Re Utilities Asset Disposition* was upheld in ***FortisAlberta***, which found that the Commission's decision was "reasonable and well within its statutory authority". Specifically, excluding the value of a stranded asset from the rate base was not inconsistent with the principle

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that the utility is entitled to recover its prudent operating costs as well as receive a fair return on its capital investments. The cost of depreciable assets that are withdrawn from service in the ordinary course of business will have been recovered through the depreciation expense component of rates: ***FortisAlberta*** at para. 140. The symmetrical treatment of gains and losses requires that the utility shareholders who are exclusively benefiting from any gain on the disposition of stranded assets must exclusively bear the risk of loss: ***FortisAlberta*** at para. 141.

[32] ***FortisAlberta*** concluded the effect of the Commission's approach was that the cost of depreciable assets would be reflected in the utilities' prudent expenses through the accepted depreciation provisions. Since the approved depreciation mechanisms operated on a "mass account" basis, the cost of all depreciable assets would be recovered over time, even if any one asset happened to last longer or shorter than the depreciation schedule had anticipated. Losses arising from extraordinary depreciation events, such as destruction of the property, were not however considered expenses to be included in the rate base, because these risks were properly on account of the shareholders, not the ratepayers. ***FortisAlberta*** at para. 144-45 concluded that this was a reasonable approach.

[33] Some of the key points from ***FortisAlberta*** are as follows:

(a) Like *Re Utilities Asset Disposition* it was a generic, policy-based decision. It did not consider any particular expense, loss, or specific incident of stranding. It did not approve any particular tariff as being just and reasonable. It may reflect some of the problems that can arise when sweeping statements of the law are made in decisions that are not anchored to a particular fact situation.

(b) Like ***Stores Block***, ***FortisAlberta*** primarily dealt with assets properly included in the rate base on a going-forward basis. The withdrawal of assets from the future rate base, however, did not automatically give the answer to the treatment of the historic cost of stranded assets.

(c) ***FortisAlberta*** went further than ***Stores Block***, in finding reasonable the approach of the Commission that any "extraordinary retirement" relating to assets was on the account of the shareholders. This was not limited to "losses of value", but also covered destruction of assets such as by forces of nature.

(d) The decision relied heavily on the reasonableness of the Commission's treatment of depreciation. Losses arising from extraordinary depreciation events, such as destruction of the property, would not be considered expenses to be included in the rate base.

[34] As noted, in the decision presently under appeal the Commission felt itself bound by its interpretation of ***Stores Block*** and ***FortisAlberta***. The outcome of this appeal turns largely on the correctness of that interpretation.

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The Present Appeal from the Z Factor Decision

[35] With respect to the second issue on which the appellant was given permission to appeal, it argues that the Commission erred in three ways:

(a) The Commission failed to have regard for the obligation to provide a reasonable opportunity for ATCO to recover its prudent capital investment, which is both a core principle of the regulatory compact, and an express statutory requirement under the *Electric Utilities Act*;

(b) By disregarding the requirements of the *Electric Utilities Act*, the Commission gave primacy to principles it derived from legislation applicable to other utilities, and in part, expressly inapplicable to electric utilities; and

(c) The Commission's analysis results in an absurdity, marked by inconsistent results, controversy recognized by commentators, this Court, and even the Commission itself, which cannot be what the Legislature intended.

The first and third issues can be summed up by stating that the Commission misinterpreted or overread ***Stores Block*** and ***FortisAlberta.*** It wrongly felt that it was obliged to apply certain principles to the decision before it, whereas in fact it had a much wider discretion. Further, it failed to focus on the actual issue before it, which was to set a just and reasonable tariff. The second ground of appeal can briefly be disposed of.

Application of Rules That Do Not Apply to Electric Utilities

[36] The applicant notes that the ***Stores Block*** decision related to regulation of a gas utility, and some of the reasoning built on the particular wording of the applicable statute. Electric utilities are regulated under a different statute, which has different wording. Nevertheless, ***FortisAlberta*** at paras. 6, 32, 116, 161, 167 specifically considered this issue and concluded that the Commission's finding that the basic principles apply to all utilities was reasonable. Indeed, in this appeal the appellant relies on general statements about cost recovery in utility regulation found in cases like ***ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)***, 2015 SCC 45, [2015] 3 SCR 219 (***Pensions Appeal***) and ***Northwestern Utilities Ltd. v City of Edmonton***, [1929] SCR 186, both of which related to gas utilities.

[37] In *Utilities Asset Disposition* the Commission considered the statutory interpretation arguments again made here by the appellants: ***FortisAlberta*** at para. 163. In that decision the Commission concluded that its fundamental function was to fix just and reasonable rates and to protect the integrity and dependability of the supply system. This fundamental objective was universal to all types of utilities and was not varied by the different wording in the statutes.

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[38] The appellant notes that *Utilities Asset Disposition* relied on the requirement that gas utility assets must be "used or required to be used" to be in the rate base. Those words are not found in the *Electric Utilities Act*. Nevertheless, it cannot be unreasonable for the Commission to exclude from the calculation of a just and reasonable tariff assets that are not used or required to be used to distribute electricity. While the wording of the statutes may be different, the underlying concepts are the same, and parallel issues arise respecting stranded assets.

Setting a Just and Reasonable Tariff

[39] The Commission is routinely required to set rates or just and reasonable tariffs for utilities. Sometimes it must deal with collateral issues, such as the profits from the sale of assets in ***Stores Block***, or the treatment of revenue streams from assets such as in ***ATCO Gas and Pipelines Ltd v Alberta (Energy and Utilities Board)***, 2008 ABCA 200, 433 AR 183, 91 Alta LR (4th) 77 (***Carbon Storage***). But one of its core functions can be said to be the setting of tariffs.

[40] The fundamental issue before the Commission was where losses arising from forces of nature during normal operations, such as the Fort McMurray wildfire, should fall: on the consumers of the utility or on the utility's shareholders?

[41] The foundation for this appeal is found in s. 121-22 of the *Electric Utilities Act*:

> 121(1) On giving notice to interested parties, the Commission must consider each tariff application.
>
> (2) When considering whether to approve a tariff application the Commission must ensure that
>
> > (a) the tariff is just and reasonable,
> >
> > (b) the tariff is not unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of this or any other enactment or any law, and
> >
> > (c) if the regulations so require, the tariff incorporates the standard of liability imposed by the regulations made by the Lieutenant Governor in Council under section 94, or that the Commission has, in accordance with those regulations, considered and imposed a standard of legal liability that it considers appropriate.
>
> (3) A tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives.

(4) The burden of proof to show that a tariff is just and reasonable is on the person seeking approval of the tariff.

122(1) When considering a tariff application, the Commission must have regard for the principle that a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover

> (a) the costs and expenses associated with capital related to the owner's investment in the electric utility, including
>
> > (i) depreciation,
> >
> > (ii) interest paid on money borrowed for the purpose of the investment,
> >
> > (iii) any return required to be paid to preferred shareholders of the electric utility relating to the investment,
> >
> > (iv) a fair return on the equity of shareholders of the electric utility as it relates to the investment, and
> >
> > (v) taxes associated with the investment,
>
> if the costs and expenses are prudent and if, in the Commission's opinion, they provide an appropriate composition of debt and equity for the investment,
>
> (b) other prudent costs and expenses associated with isolated generating units, transmission, exchange or distribution of electricity or associated with the Independent System Operator if, in the Commission's opinion, they are applicable to the electric utility,
>
> (c) amounts that the owner is required to pay under this Act or the regulations,
>
> (d) the costs and expenses applicable to the electric utility that arise out of obligations incurred before the coming into force of this section and that were approved by the Public Utilities Board, the Alberta Energy and Utilities Board or other utilities' regulatory authorities if, in the Commission's opinion, the costs and expenses continue to be reasonable and prudently incurred,

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> (e) its prudent costs and expenses of complying with the Commission rules respecting load settlement,
>
> (f) its prudent costs and expenses respecting the management of legal liability,
>
> (g) the costs and expenses associated with financial arrangements to manage financial risk associated with the pool price if the arrangements are, in the Commission's opinion, prudently made, and
>
> (h) any other prudent costs and expenses that the Commission considers appropriate, including a fair allocation of the owner's costs and expenses that relate to any or all of the owner's electric utilities.

The appellant points to the mandatory language in this section, entitling it to a "just and reasonable tariff", that "must provide the owner of an electric utility with a reasonable opportunity to recover" prudently incurred costs. The statute must be read as a whole, and it is not helpful to treat one part of these provisions as being "subordinate" to any other. Even though total cost recovery is not guaranteed, a tariff is unlikely to be just and reasonable if it does not provide a reasonable opportunity to recover prudently incurred costs.

[42] The appellant also points to statements in the case law which recognize the basic concept that regulated utilities should be allowed to recover their prudent costs: e.g. ***Pensions Appeal***; ***Ontario (Energy Board) v Ontario Power Generation Inc***., 2015 SCC 44 at paras. 15-16, [2015] 3 SCR 147 and ***Northwestern Utilities***. That being said, the Commission is still left with a considerable degree of discretion in setting tariffs. It is acknowledged that the regime does not guarantee the recovery of all costs: ***FortisAlberta*** at para. 158.

[43] For example, while the statute mentions "depreciation", it does not impose any particular methodology for dealing with it. There is nothing specific about dealing with stranded assets. As stated in ***FortisAlberta*** at para. 29, "a wide range of regulatory methods exist for dealing with stranded costs and assets". Whether an expenditure was "prudent" is also in the hands of the Commission: ***Pensions Appeal*** at paras. 46-47. The appellant concedes that the statute does not guarantee the recovery of all costs in all circumstances. That places the ultimate treatment of stranded assets within the discretion of the Commission. Likewise, it falls to the Commission to consider what would be the just and reasonable treatment of losses from the unexpected and permanent removal from service of prudently acquired assets.

[44] The important point is that the *Electric Utilities Act* leaves a broad discretion on these issues to the Commission, and there is nothing in ***Stores Block*** or ***FortisAlberta*** to the contrary. ***Stores Block*** was not about setting reasonable and just tariffs, it was primarily concerned with the

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treatment of profits on the sale of assets, and it did not purport to limit the Commission's discretion to deal with depreciation and assets destroyed by forces of nature. As noted, ***FortisAlberta*** was a generic, policy-based decision that had no particular facts before it. While it spoke in generic terms about losses due to the forces of nature, it did not have before it specific facts such as the losses caused by the Fort McMurray wildfire. Far from mandating a particular approach, ***FortisAlberta*** recognized the Commission's wide discretion:

> 140 Subject to the limits on its discretion imposed by legislation, as interpreted by *Stores Block* and the subsequent pronouncements from this Court, the Commission ultimately must choose among available options to address the problem of how to deal with stranded assets, and how to apportion the risk associated with the loss of assets through extraordinary events. . . .

In short, the Commission erred in thinking that these earlier decisions dictated its treatment of assets stranded by unforeseen forces of nature. No binding authority compels relying on the accounting details underlying the predicted survival curves of the asset pools to decide how to deal with assets unexpectedly and permanently removed from active service by forces of nature.

[45] In the Z Factor decision presently under appeal, the Commission recognized that the outcome was ultimately tied back to the need to set a just and reasonable tariff. It, however, overread the implications of ***Stores Block*** and ***FortisAlberta***:

> 130 The Commission's finding that costs of the retirement event should be allocated to shareholders results in just and reasonable rates. This finding is consistent with the governing legislation, the fundamental property and corporate law principles established by the courts and the guidance of the courts on the allocation of risk and benefits associated with property ownership. This guidance was reviewed by the Commission in the UAD decision and subsequently upheld on appeal. The guidance limits the Commission's flexibility in dealing with cost allocation upon the retirement of utility assets, both those reasonably anticipated and those that are unanticipated.

There is, however, nothing in the *Electric Utilities Act* that limits the Commission's discretion over depreciation or stranded assets. The "allocation of risks and benefits associated with property ownership" and "fundamental property and corporate law principles" are only of peripheral importance to determining if a utility should be given the opportunity to recover prudently incurred costs. Any "guidance" in the previous decisions were merely affirmations that the Commission has a wide discretion in this area. It is inconsistent to suggest that such "guidance" would have the effect of limiting the "Commission's flexibility in dealing with cost allocation upon the retirement of utility assets".

[46] The outcome here was not inevitable or driven by any binding precedent. It is conceded that the destroyed assets were prudently purchased. They were actively being used to provide

electrical service when they were destroyed. There is nothing inherently unjust about allowing the utility to recover these costs. It can easily be argued that the risk of fire loss from natural causes should be spread among the customers who benefit from the service being provided, not placed on the shareholders.

[47] There is no issue of "symmetry" involved because there is no possibility of a utility making a profit from the stranding of an asset because it was destroyed by fire. In *Utilities Asset Disposition* the Commission concluded at para. 271 that the "utility asset ownership principles" it identified applied equally to dispositions of property inside or outside the ordinary course of business:

> . . . To hold otherwise and find that it is customers that receive the benefit of any gain or bear the risk of any loss for utility property other than in the case where it is disposed of outside of the ordinary course of business would mean that customers must have acquired some sort of property interest in those assets, contrary to the findings of the court in *Stores Block*, . . . It is inconsistent with the principles and *Stores Block* to suggest that customers do, or do not, gain a property interest in utility property, and receive the gains or bear the losses accordingly, depending on the nature of the circumstances of the disposition of the asset.

There is, however, nothing about allowing the utility to recover the costs of the damage caused by the Fort McMurray wildfire that implies that somehow the customers had obtained a property interest in those assets. This extrapolation of the principles in ***Stores Block*** demonstrates how that case said nothing about the destruction of assets by forces of nature. ***Stores Block*** concerned economic losses and gains on disposition, not physical destruction.

[48] The assets in question were consumed by the fire while they were being used to provide utility services, and the issue is whether it is fair to the customers and the utility that the customers bear that loss, which in turn is tied back to the wording of the *Electric Utilities Act*. Even if the ultimate decision is that it is just and reasonable that the losses fall on the utility's shareholders, that is not because of the difference between ordinary and extraordinary retirements, or whether the customers have any ownership interest in the destroyed assets.

[49] Z Factor Adjustments are permitted to allow variation of what was previously set as a just and reasonable tariff. They are designed to account for exogenous events outside the control of the utility, and for which the utility has no other reasonable opportunity to recover the cost. Exceptional losses, by their very nature, are unlikely to have been factored in when the original tariff was set. *Prima facie* the damage caused by the Fort McMurray wildfire falls within this definition. It seems counterintuitive to actually disallow the recovery of prudent costs because of Z factors.

[50] As noted, the Commission relied on its prevailing depreciation provisions in dealing with the losses caused by the Fort Murray wildfire. The "mass property account" approach was

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summarized *supra*, para. 7. The assets destroyed by the Fort Murray wildfire would have been included in one or more of these mass property accounts.

[51] In *Re Utility Asset Disposition* the Commission directed at para. 327 that assets retired through "extraordinary circumstances" had to be removed from the rate base because they were no longer used to provide the service:

> As stated above, these types of assets must be retired (removed from rate base) and moved to a non-utility account because they have become no longer used or required to be used as the result of causes that were not reasonably assumed to have been anticipated or contemplated in prior depreciation or amortization provisions.
> . . .

This included "property that should be removed because of circumstances including unusual casualties (fire, storm, flood, etc.)". There is, however, no obvious reason why assets retired through "ordinary circumstances" should be treated any differently.

[52] The source of this distinction is said to be ***Stores Block***, but as previously noted the facts were different. ***Stores Block*** primarily discussed assets in the rate base to point out that inclusion of the costs of assets in the rate base did not mean that the customers obtained an ownership interest in those assets. In that case the Stores Block land and building had at one time been used to provide utility services, so their costs were included in the rate base. The property became surplus to requirements and when it was sold, the proposal was to retire the remaining net book value, which would effectively withdraw those expenses from the rate base. No further depreciation from that asset or pool would be charged to the customers. There would in addition be a profit, which the Supreme Court determined belonged to the shareholders of the utility.

[53] The distinction is that in the case of the Fort McMurray wildfire there are no proceeds from the destruction of the assets. There is nothing to use to retire the remaining net book value, and obviously no profit to be allocated between the utility's customers and shareholders. In ***Stores Block*** the Stores Block assets were no longer used for the provision of utility services, they therefore had to be withdrawn from the rate base, and then they were subsequently disposed of. In this appeal the assets in question were continuously used to provide utility services up to the moment they were destroyed. They were never removed from the system because they were no longer used to provide services, up until the date of their destruction. The distinction is that the assets destroyed by the Fort McMurray wildfire ceased to be used for the distribution of electricity because they were destroyed. A comparative situation would have arisen if the Stores Block buildings had been destroyed by fire while they were still being actively used to provide utility services.

[54] Despite its discussion about the need for symmetry between gains and losses on surplus assets, the ***Stores Block*** decision should not be read as extending to situations where assets in active service are destroyed by natural forces. In the latter situation, the question is whether it is

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just and equitable to continue to give the utility a reasonable opportunity to recover the costs prudently incurred, not where the ownership interests lie. Wildfires are not a risk of property ownership, they are a risk of operating a utility in an environment subject to uncontrollable and unpredictable forces of nature.

[55] The issue that had to be determined by the Commission was how the undepreciated capital cost of destroyed pool assets should be treated. As noted, the Commission concluded the treatment should vary depending on whether the asset is the subject of an "ordinary retirement" or an "extraordinary retirement":

> 89 In the UAD decision, the Commission confirmed that ordinary retirements result from causes reasonably assumed to have been anticipated or contemplated in prior depreciation provisions, and may normally be expected to occur when a plant reaches the end of its expected service life. Under-recovery or over-recovery of capital investment on ordinary retirements are for the account of customers.

"Extraordinary retirements" on the other hand occurred when the event under which the asset was removed from service had not been taken into account in setting the depreciation parameters. The distinction is not made, for example, based on the type of loss (wildfire), whether it occurred in the ordinary course of business, or when the loss occurred. Rather the distinction is based on the predicted survivor curve developed by the accountants when they predicted the average service life for that pool of assets. The connection of this distinction to just and reasonable rates and a fair opportunity to recover prudent costs is elusive.

[56] The distinction drawn by the Commission between ordinary retirements and extraordinary retirements is not driven by the decision in ***Stores Block***. ***Stores Block*** did not make that distinction and did not cover what should be done with depreciable assets that were destroyed while in service and therefore withdrawn from service. That distinction may be helpful for some kinds of removal of assets from service, but its application to destruction by the forces of nature is artificial. As the appellant points out, the approach taken means that some utilities have been allowed to recover the losses from the very same wildfire, whereas the appellant has not.[4] To summarize again, the ultimate issue is whether the destroyed assets were prudently acquired, whether they were related to the provision of the utility service to customers, and whether the utility had been given a reasonable opportunity to recover those costs. At the end of the day, should the unexpected loss from forces of nature fall on the utility's customers or shareholders? No answer to those questions

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[4] Other utilities were allowed to recover similar damage from this same fire: see *ATCO Electric Ltd, Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire*, AUC Decision 21609-D01-2019; *ATCO Gas, a Division of ATCO Gas and Pipelines Ltd, Z Factor Application for Recovery of 2016 Regional Municipality of Wood Buffalo Wildfire Costs*, AUC Decision 21608-D01-2018, and Lou Cusano et al, *Prudence, Stranded Assets, and the Regulation of Utilities: A Review of Alberta Utility Regulatory Principles in a Post-Stores Block Era* (2018) 56:2 Alta L Rev 403.

emerges from characterizing the retirement as "ordinary" or "extraordinary" depending on whether it was anticipated in the preparation of the survivor curve for that type of asset.

[57] If a particular type of loss, outside the control of management of the utility, was not anticipated in the survivor curve, one could make an argument that this increases the legitimacy of the utility recovering that cost. Based on their definition, that appears to be what the Z Factor adjustments are for. The problem is with the inadequacy of the survivor curve as a predictor of the average life of the assets, not with the expenditure. Whether the losses from things like wildfires should fall on the customers of the utility, or on the utility itself, is partly a policy decision, but it has nothing to do with whether the customers have any ownership interest in the destroyed assets. It has to do with whether it is fair to expect the customers to bear the risks of unexpected and uncontrollable losses that occur in the operation of the utility, considering, for example, that a decision was made to self-insure these risks to save the customers money. Assimilated with this is the statutory right of the utility to be given a fair opportunity to recover its prudently incurred costs.

[58] Again, it is not obvious why the treatment of the remaining undepreciated book value of an asset removed from service because it was destroyed by a wildfire should differ depending on whether this level of risk was factored into the depreciation schedules. If the ownership of the asset by the shareholders determines where the losses should lie, one has to question why the loss would shift just because the person who set the survivor curve was more prescient about the risks from natural forces faced by the utility. If placing the losses from wildfires on the utility customers implies that they had an ownership interest in the destroyed assets, why is there any difference between whether the loss was "ordinary" or "extraordinary"? Why does one form of loss, or treatment in the depreciation schedules, imply an ownership interest, but not the other? Some of the anomalies that can result from the Commission's treatment of losses of this type were identified by Acting Commissioner Lyttle, concurring in *ATCO Electric Ltd. 2018-2019 Transmission General Tariff Application*, decision 22742-D02-2019, at paras. 73-76, 80-81, 83.

[59] The ultimate balancing of these competing policy considerations is for the Commission. The Commission, however, erred in thinking that the ***Stores Block*** decision dealt with this issue, much less that it bound the Commission to the approach it has taken.

Summary and Conclusion

[60] To summarize, the issue is where the losses resulting from forces of nature should fall: on the utility's consumers or on the utility's shareholders:

(a) In legal terms the issue is where a just and reasonable tariff would place those losses, having due regard to the right of the utility to a reasonable opportunity to recover its prudent costs.

(b) This issue was not decided by ***Stores Block*** or ***FortisAlberta***.

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(c) The analysis cannot start with an assumption that it is inherently fair to place the burden on one group or the other. That is the answer, not the premise of the question.

(d) It is relevant that the utilities stopped buying insurance to save the consumers money. The Commission apparently decided that it was prudent for the consumers to self-insure.

(e) The answer does not lie in whether the loss was or was not anticipated in the survivor curve behind the depreciation schedules, or whether the loss was therefore ordinary or extraordinary.

(f) The answer also does not arise from "fundamental property and corporate law principles" or property ownership of the destroyed assets. Loss by fire is not a part of disposition law.

Ultimately the question lies within the discretion of the Commission, to be exercised consistently with the words of the *Electric Utilities Act*, having regard to all relevant considerations, while disregarding irrelevant ones.

[61] In conclusion, the decision under appeal is based on errors of law, particularly the conclusion that the Commission's options for treating destroyed assets were constrained by ***Stores Block***. The setting of rates is clearly within the discretion of the Commission, including the determination of what expenses can be included as recoverable costs and expenses, how to deal with depreciation, and how to deal with stranded or unpredictably destroyed assets.

[62] The appeal is allowed. Section 29(11)(c) of the *Alberta Utilities Commission Act* provides that where this Court gives directions to vary a decision "the Court shall refer the matter back to the Commission for further consideration and redetermination". The application is accordingly returned to the Commission for reconsideration.

Appeal heard on April 4, 2023

Memorandum filed at Calgary, Alberta
this 14th day of April, 2023

Watson J.A.

Slatter J.A.

Authorized to sign for: Kirker J.A.

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