In the Court of Appeal of Alberta

Citation: FortisAlberta Inc v Alberta Utilities Commission, 2026 ABCA 258

Date: 20260731
Docket: 2301-0264AC;
2301-0265AC;
2301-0268AC
Registry: Calgary

Docket: 2301-0264AC

Between:

FortisAlberta Inc.

Appellant

- and -

Alberta Utilities Commission and Office of the Utilities Consumer Advocate

Respondents

Docket: 2301-0265AC

Between:

ENMAX Power Corporation

Appellant

- and -

Alberta Utilities Commission and Office of the Utilities Consumer Advocate

Respondents

Docket: 2301-0268AC

Between:

ATCO Electric Ltd.

Appellant

- and -

Alberta Utilities Commission and Office of the Utilities Consumer Advocate

Respondents

The Court:

The Honourable Justice Alice Woolley
The Honourable Justice Tamara Friesen
The Honourable Justice Karan Shaner

Memorandum of Judgment

Appeal from the Decision of the
Alberta Utilities Commission
Dated the 4th day of October, 2023
Decision 27388-D01-2023

Memorandum of Judgment

The Court:

Introduction

[1] Alberta consumers obtain electricity through a competitive retail market and regulated distribution and transmission services. The appellants – ATCO Electric Ltd, ENMAX Power Corporation, and FortisAlberta Inc – are distribution utilities, each of which provides distribution services within a specific service area, generally on an exclusive basis. The distribution utilities assume a duty to adequately and reliably serve all customers in their service area and submit to regulation by the Alberta Utilities Commission under the *Electric Utilities Act*, SA 2003, c E-5.1, including with respect to the rates they charge to customers: *ATCO Gas & Pipelines Ltd v Alberta (Energy & Utilities Board)*, 2006 SCC 4 at para 63. Rates must be "just and reasonable", meaning fair to both consumers and the utility: *Electric Utilities Act*, s 121(2)(a); *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2015 SCC 45 at para 7.

[2] Since 2009 for ENMAX, and since 2013 for all distribution utilities, the rates paid by customers for distribution services have been set using a performance-based regulation model. The Commission decision which is the subject of this appeal set the parameters for the third performance-based regulation term, which runs from 2024-2028: *2024-2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities*, AUC Decision 27388-D01-2023 (4 October 2023) [*Third Term Decision*].

[3] The appeal challenges a core aspect of the shift to performance-based regulation, raising the question of how to ensure fairness to utilities and customers when decoupling the rates paid by customers from a utility's forecast costs over a several year period. In particular, the appellants submit that, when it set rates for the third term of performance-based regulation, the Commission erred in its approach to supplemental capital funding. As a consequence, they say, it has denied them the reasonable opportunity to recover their prudently incurred costs, including a fair return on equity, contrary to s 122(1) of the *Electric Utilities Act*.

[4] In addition – and unrelated to the fundamental structure of performance-based regulation – Fortis submits the Commission erred by providing no explanation for its refusal to adjust its rates to account for the financial risks associated with its obligation to permit rural electrification associations to make use of its distribution system.

[5] For the reasons that follow, we allow Fortis's appeal related to the sufficiency of the Commission's reasons but dismiss the grounds of appeal related to supplemental capital funding.

The appellants have not established that the Commission's approach to supplemental capital funding denies them a reasonable opportunity to recover their prudently incurred costs, or to earn a fair return on equity. As a result, we do not consider the Office of the Utilities Consumer Advocate's application to introduce fresh evidence related to the return on equity earned by the appellants in the first year of the third performance-based regulation term.

Performance-based regulation in Alberta

[6] Prior to 2013, Alberta's distribution utilities were largely regulated under a "cost of service" regulation model: *Rate Regulation Initiative Distribution Performance-Based Regulation*, AUC Decision 2012-237 (12 September 2012) at paras 5, 14 [*First Term Decision*].

[7] Under cost of service regulation, a regulator assesses the forecast total amount of money a utility needs to provide its regulated services in a year. This amount, called the "revenue requirement", consists of the "total annual operating, maintenance and administrative expenses of the company plus the company's capital-related costs": *First Term Decision* at para 7. The capital costs depend on the value of the assets owned by the utility; a utility's assets are its "rate base". The assets in rate base depreciate in value; they are also financed through a combination of debt, on which the utility pays interest, and equity, on which the utility earns an approved rate of return. Thus, a utility's annual revenue requirement under cost of service regulation is the total forecast amount of 1) its operating, maintenance and administrative expenses; 2) the amount of depreciation on its assets; 3) the cost of its debt; and 4) the return on its equity. The "return on equity actually earned is sometimes referred to as the utility company's profit since all other expenses and costs (operating, maintenance, administration and debt costs) are recovered without any profit margin built into them": *First Term Decision* at para 7.

[8] Applying the cost of service methodology, the Commission determined a utility's revenue requirement on a forecast basis, generally for a two-year period. The utility would submit its forecast maintenance, operating and administrative expenses, and its forecast capital-related costs, to the Commission. The Commission would then review the utility's submitted forecasts for reasonableness, both in relation to the nature and quantum of a particular expenditure. If, for example, the utility planned to acquire new administrative offices, the Commission would consider the reasonableness of the utility acquiring new offices and of the amount it proposed to pay for them.

[9] The incentive structure of cost of service regulation arose from the ability of a utility to retain amounts earned from providing its services at less than the approved forecast amount, with savings from those efficiencies being passed on to consumers at the next cost of service review. Over time, however, the limited effectiveness of that incentive structure became obvious. The utility would benefit only from investments in efficiency that could be recovered over the short cost of service rate period and thus had limited incentives to pursue longer term improvements. In addition, exclusive reliance on forecasting encouraged utilities to engage in problematic behaviour, namely, providing forecasts of operating and maintenance and capital costs that were higher than

what the company expected to achieve, or forecasts about the number of customers and other billing units that were lower than what the utility expected to achieve, thereby effectively "increasing profits above the approved return": *First Term Decision* at para 11. Cost of service regulation also encouraged utilities to spend "money on capital assets, on which a return can be earned, over spending on maintenance, for example, on which a return is not earned": *First Term Decision* at para 11. A utility had no incentive to minimize the costs of capital assets.

[10] Additional issues arose with cost of service regulation because of the restructuring of the electricity industry and the introduction of competition to the generation and retail aspects of the business. Deregulation required costs to be allocated between regulated and unregulated affiliates of the same corporation, introducing considerable regulatory complexity: *First Term Decision* at para 12. That complexity was compounded by the nature of the regulatory proceedings themselves, which had become longer and more evidence intensive: *First Term Decision* at para 13.

[11] In short, the Commission came to understand that cost of service regulation did not provide sufficient incentives for a utility to be efficient and reduce its costs; encouraged utilities to over invest in capital; and did not provide a mechanism to manage regulatory complexity and costs: *First Term Decision* at para 14.

[12] Performance-based regulation was adopted to address these difficulties. Performance-based regulation begins by establishing "going-in rates" during a rebasing year based on forecast costs, often determined through a cost of service proceeding. Then, in each subsequent year of the plan term, the base rate is adjusted mechanically by applying a multiplier equal to the "rate of inflation (I) relevant to the prices of inputs the companies use less an offset (X) to reflect the productivity improvements the companies can be expected to achieve", an adjustment mechanism referred to as "I-X": *First Term Decision* at para 16.

[13] Using the annual I-X adjustment mechanism rather than re-establishing rates through a cost of service proceeding breaks the link between the utility's costs and revenues during the performance-based regulation term. As a result, the company's actual performance will "depend on how its own performance compares to the industry's inflation and productivity measures": *First Term Decision* at para 16. This creates a stronger incentive to improve efficiency because companies can retain the increased profits generated by cost reductions longer than they would under cost of service regulation. Customers share in expected productivity gains through the application of the productivity X factor and also when realized cost reductions are passed on to them at rebasing through lower going-in rates for the next performance-based regulation term.

[14] The five principles for performance-based regulation adopted by the Commission at the outset, and maintained since, are:

> **Principle 1**. A PBR plan should, to the greatest extent possible, create the same efficiency incentives as those experienced in a competitive market while maintaining service quality.

> **Principle 2**. A PBR plan must provide the company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return.
>
> **Principle 3**. A PBR plan should be easy to understand, implement and administer and should reduce the regulatory burden over time.
>
> **Principle 4**. A PBR plan should recognize the unique circumstances of each regulated company that are relevant to a PBR design.
>
> **Principle 5**. Customers and the regulated companies should share the benefits of a PBR plan.
>
> *First Term Decision* at para 28.

[15] A performance-based regulation term usually lasts for five years, at which time rates are generally re-established in a cost of service "rebasing" proceeding. A further performance-based regulation term then begins based on those new going-in rates: *First Term Decision* at para 22.

[16] From the outset, and with shifts over time to reflect experience, performance-based regulation has supplemented and adjusted the base rate calculated using the I-X adjustment mechanism. The point of those supplements and adjustments is to better ensure the benefits of performance-based regulation are shared with customers, to avoid an increasing regulatory burden, and to reflect the operational needs of the distribution utilities, including the requirement that they have a reasonable opportunity to recover their prudently incurred costs, including a fair return on equity.

[17] First, rates under performance-based regulation have a specific adjustment – the "Y factor" – to flow certain costs outside management's control, such as municipal fees, through to customers: *Third Term Decision* at 118; *2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities*, Decision 20414-D01-2016 (Errata) (6 February 2017) at 89 [*Second Term Decision*].

[18] Second, rates under performance-based regulation have a specific adjustment – the "Z factor" – to account for the "significant financial impact (either positive or negative) of an exogenous event outside of the control of the distribution utility and for which the distribution utility has no other reasonable opportunity to recover the costs": *Third Term Decision* at 119; *Second Term Decision* at 91.

[19] Third, rates under performance-based regulation incorporate mechanisms to ensure that gains achieved due to increased efficiencies during a rate period are shared with customers. In the *Third Term Decision*, the Commission required the distribution utilities to share with customers earnings more than 200 basis points above the approved rate of return on equity: *Third Term Decision* at paras 332-336, 344-366. In addition, the Commission increased the productivity X

factor used to adjust rates each year by applying an additional 0.3 percent "benefit-sharing premium" to share with customers expected gains earned during the performance-based regulation term on a predetermined and guaranteed basis: *Third Term Decision* at paras 337, 341-342. The Commission then further increased the productivity factor, as compared to historical industry productivity growth, by applying a "stretch factor": *Third Term Decision* at paras 148, 154, 163.

[20] Fourth, under performance-based regulation, a utility's rates include a re-opener provision to "safeguard against unexpected results that could signal that there is a problem with the design or operation of the plan that makes its continued operation untenable". In the first two terms of performance-based regulation, if the earned return on equity was 500 basis points above or below the approved rate of return on equity in a single year, or 300 basis points above or below the approved rate in two consecutive years, the Commission would consider whether to reopen and review the plan: *Third Term Decision* at para 374. In the third term, with the introduction of the earnings sharing mechanism, the reopener is triggered only if the earned return on equity is 300 basis points below the approved rate over two consecutive years, or 500 basis points above or below the approved rate in a single year: *Third Term Decision* at paras 376-377.

[21] Fifth, and central in this proceeding, the Commission has supplemented the I-X adjusted base rate with additional funding to support capital expenditures.

[22] From the outset of performance-based regulation, the Commission acknowledged that the amount of capital expenditures made by a utility on an ongoing basis will not be sufficiently funded only by applying the I-X adjustment mechanism to the base rate. Supplemental capital funding is provided in "virtually every jurisdiction" using performance-based regulation, and responds to the "long-term, lumpy and cyclical nature of capital investments": *Third Term Decision* at para 178.

[23] At first, the Commission adopted a capital tracker methodology to determine the level of supplemental funding, allowing "a regulated firm to track and begin to recover the costs associated with certain capital projects" outside of the I-X adjusted base rate. The utility was required to "demonstrate that a necessary capital replacement project or capital project required by an external party" could not "reasonably be expected to be recovered through the I-X mechanism": *First Term Decision* at paras 575, 586-587, 592.

[24] In the *Second Term Decision*, the Commission abandoned capital trackers as the primary source of supplemental capital funding. The Commission explained that its experience over the first term of performance-based regulation demonstrated that utilities had "considerable flexibility" in the timing of their capital expenditures, such that their capital needs could be met through a general funding supplement rather than by funding particular projects. It also pointed out that capital tracker proceedings were associated with an increased regulatory burden relative to a more general funding mechanism, and that as a form of cost of service rate making "they were not subject to the same high-powered incentives to control costs" that arise from a pure performance-based regulation structure: *Second Term Decision* at paras 152, 196, 211-214.

[25] The Commission adopted a dual stream approach to supplemental capital funding as proposed by a consumer advocate and several of the utilities, including Fortis. Under this approach, supplemental funding for extraordinary "Type 1" capital projects would continue to be provided through capital trackers, but the bulk of supplemental capital funding would be provided through a "Type 2" general funding envelope. The Commission acknowledged that the Type 2 capital funding envelope created some risk for the utilities; however, it found that making too much capital subject to the Type 1 capital tracker mechanism would unduly reduce the incentive structure of performance-based regulation, would not account for utilities' flexibility to manage capital expenditures, and would decrease regulatory efficiency: *Second Term Decision* at paras 189, 196-199, 214.

[26] In the Commission's view, providing specific funding for particular projects only in exceptional cases, while providing a general envelope of supplemental funding for capital additions, would maximize "the ability of each distribution utility to manage its business and to discover and pursue efficiencies and cost saving by providing flexibility in how it plans and allocates capital funding", while ensuring the utility fulfills its obligation to serve its customers. It would also reduce the regulatory burden associated with capital trackers: *Second Term Decision* at para 214.

[27] Consistent with this logic, the Commission identified two narrow criteria for the utility to meet in order for a proposed capital project to fall within the Type 1 category:

> (i) The project must be of a type that is extraordinary and not previously included in the distribution utility's rate base.
>
> (ii) The project must be required by a third party.
>
> *Second Term Decision* at para 198.

[28] The Commission decided to base the Type 2 supplemental funding envelope on an average of historical additions, as opposed to forecasted capital additions. Using historical actuals involved "less regulatory burden than the testing of a full ... forecast for all capital programs", and forecasting would create an "incentive for distribution utilities to over-forecast" and cause difficulties because of the "asymmetrical information available to parties": *Second Term Decision* at para 245.

[29] For the second term of performance-based regulation, the Type 2 supplemental funding calculation – the "K-bar" calculation – involved comparing the revenue recovered through the base rates under the I-X mechanism for capital projects (step 1) to the notional revenue requirement for capital projects based on an average of historical levels of actual capital additions over four years, adjusted to account for the effects of inflation, productivity, and customer growth (step 2).

[30] With minor adjustments, some of which are discussed below, the Commission continued to apply this approach to both Type 1 and Type 2 capital in the *Third Term Decision*. While the distribution utilities generally met or exceeded their approved returns on equity during the second performance-based regulation term, they nonetheless argue that the continued used of this approach does not give them a reasonable opportunity to recover their prudently incurred costs, including a fair return on equity, during the third performance-based regulation term.

Issues and standard of review

[31] The general issue on appeal is whether the Commission erred in establishing the parameters for the third performance-based regulation term. In particular:

(a) Did the Commission err by failing to provide the appellants a reasonable opportunity to recover their prudently incurred capital costs, including a fair return on equity, by:

(i) Exclusively relying on their average historical capital additions in step 2 of the supplemental capital K-bar calculation?

(ii) Adjusting the productivity X factor when applying it to the supplemental capital K-bar calculation?

(iii) Unreasonably restricting their access to Type 1 capital funding?

(b) Did the Commission err by failing to address Fortis's submissions in favour of removing the stretch factor from the productivity X factor applied to its base rates to account for its ongoing service obligations to rural electrification associations?

[32] By virtue of the statutory authority granted to this Court to review decisions of the Commission on questions of law or jurisdiction for which permission to appeal is granted, and given the decision granting permission to appeal in this case, these issues raise questions of law to which a correctness standard of review applies: *FortisAlberta Inc v Alberta Utilities Commission*, 2025 ABCA 88; *ATCO Electric Ltd v Alberta Utilities Commission*, 2023 ABCA 129 at para 15 [*ATCO 2023*]; *Canada (Minister of Citizenship and Immigration) v Vavilov*, 2019 SCC 65 at paras 36-37 [*Vavilov*]; *Alberta Utilities Commission Act*, SA 2007, c A-37.2, s 29.

[33] That does not mean, however, that every aspect of the Commission's decision in relation to these questions is subject to a correctness review by this Court. To the extent interrelated issues of fact, policy or discretion arise as part of this Court's assessment of questions of law, the Commission's assessment of those issues of fact, policy or discretion is entitled to deference. This follows from the principles set out in *Vavilov* and *Yatar v TD Insurance Meloche Monnex*, 2024 SCC 8 at para 48, but also as a matter of relative institutional competence: *ATCO 2023* at para 16.

[34] By applying correctness review to questions of law, this Court ensures the Commission remains within its statutory authority and properly interprets the statutory direction the legislature has provided. However, the Commission is clearly empowered by the legislature to assess the facts and policies relevant and appropriate for utility rate regulation in Alberta. That assessment is entitled to deference. As this Court said in *ATCO 2023* at para 16, "by enacting a statutory appeal route the Legislature did not intend that the Court would take over the management of the electrical distribution and transmission system in Alberta": see also, *FortisAlberta Inc v Alberta (Utilities Commission)*, 2015 ABCA 295 at para 172.

Use of average historical capital additions in step 2 of the supplemental capital K-bar calculation

Third Term Decision

[35] The Commission began its analysis of supplemental capital funding by confirming the continued need for such funding given the "long-term, lumpy and cyclical nature of capital investments". It noted that supplemental capital funding had allowed the utilities to earn "greater, and in some cases, significantly greater, than the approved return" in previous performance-based regulatory terms: *Third Term Decision* at paras 178-179.

[36] The supplemental capital funding envelope for Type 2 capital calculated using the K-bar comparison also, however, resulted in "much stronger incentives to contain capital" and a significantly lower regulatory burden than the capital tracker approach used in the first term of performance-based regulation: *Third Term Decision* at para 176. It did so while still allowing the utilities a reasonable opportunity to "recover prudent costs and earn the approved rate of return when considered in the context of the total PBR2 plan": *Third Term Decision* at para 180.

[37] When the Commission held its hearing to determine the rates for the third term of performance-based regulation, the parties "generally supported the continued use of K-bar" and the "mechanics of calculating the K-bar amount". However, the parties disagreed about certain aspects of the K-bar calculation, including whether the step 2 comparator should continue to be based on historical averages, or if it should instead be based on forecasts, similar to the cost of service review used for the 2023 rebasing year to set going-in rates for the third term: *Third Term Decision* at paras 177, 183-184, 187-190.

[38] Consumer groups and EPCOR advocated using historical average capital additions over a five-year period, while the appellants proposed incorporating forecast capital additions. The Commission agreed with the consumer groups and EPCOR, observing that "the use of forecasts introduces the risk of over-forecasting, and information asymmetry can make it difficult for the Commission to assess and test forecasts without significantly increasing [the] regulatory burden". The Commission observed that the difficulty in testing forecasts is compounded in the context of performance-based regulation, where forecasts would "be for a five-year term", rather than the one-to-two-year period typical for cost of service regulation. It noted that regulators in other

jurisdictions have "acknowledged the same hesitancies regarding the approval of long-term forecasts": *Third Term Decision* at paras 195-196.

[39] The Commission pointed to and adopted its conclusion from the *Second Term Decision*, that using forecasts in the K-bar calculation risks "creating problematic incentives contrary to the intent of PBR". Although the use of a "true-up" to actual spending could ameliorate the risks associated with forecasts, it "would significantly dampen the incentive for distribution utilities to pursue efficiencies": *Third Term Decision* at paras 195, 197.

[40] The Commission did not accept the appellants' reliance on the first year of multi-year projects having been approved for the 2023 rebasing year as revealing the inappropriateness of a purely historical focus in the K-bar calculation. The approval of a single year does not extend "to the approval of all years of forecast costs for those projects" and the use of a forecast methodology for the purposes of the one rebasing year does not have "any bearing to setting K-bar for the 2024-2028 term, as that forecast methodology was specific to the 2023 COS rebasing year": *Third Term Decision* at para 198.

[41] The Commission concluded this part of its analysis by saying:

> For these reasons, the Commission … accepts the proposals … to base the capital additions for the PBR3 K-bar on the five-year average of 2018-2022 actual capital additions made under the full incentives of the PBR2 plan. <u>Doing so maximizes the incentive power of the PBR3 regime as any supplemental capital funding provided by the K-bar mechanism will provide an envelope of funding that is not dependent on distribution utilities' forecasts nor on their actual costs incurred in PBR3</u>. If the distribution utilities incur capital additions at lower levels than the 2018-2022 historical average, and/or optimize their capital and O&M spend, all else being equal, they will be able to achieve higher earnings.
>
> … [I]n the Commission's view, <u>K-bar provides an envelope of funding that is based on the assumption that it is reasonable to expect that the distribution utilities will be able to manage their business-as-usual capital activities and have a reasonable opportunity to earn an approved rate of return, if they are provided with a level of supplemental capital commensurate with their actual experience during the prior PBR term</u>.
>
> [emphasis added]
>
> *Third Term Decision* at paras 200-201.

[42] The Commission was satisfied that using historical averages in the K-bar calculation would not result in insufficient funding. It pointed out that the K-bar calculation "provides supplemental capital funding *in addition*" [emphasis in original] to funding for capital available through the base

rate as adjusted using the I-X mechanism, and that the base rate reflects the capital costs approved in the 2023 rebasing proceedings. It noted that supplemental Type 2 capital funding is a "relatively small component of the total revenue obtained under the PBR formula", citing as an example that for 2021, the base rate for ENMAX was $225 million while the Type 2 supplemental funding, as determined using the K-bar calculation, was only an additional $27 million: *Third Term Decision* at para 205.

[43] The Commission also emphasized that Type 2 funding "is not intended to provide funding on a line-by-line basis". The K-bar approach is different from the cost of service "project-by-project forecasting exercise", instead providing the utilities with a "predetermined amount of incremental capital funding". The utilities are then "expected to manage their capital programs within the capital funding constraints of the amounts provided" with the freedom to make decisions about which capital projects to pursue, and whether to divert funding towards operations and maintenance activities. The Commission said it expects "distribution utilities will continue to seek out ways to decrease costs through optimization of their existing assets, whether through implementation of non-wires solutions and operating solutions, and through modernization and automation of their systems": *Third Term Decision* at para 206.

[44] The Commission was not persuaded that the new projects considered for the purposes of the 2023 rebasing year meant the K-bar calculation would no longer provide the utilities with sufficient supplemental funding, noting that "savings from previous PBR terms weren't considered in the calculation of supplemental capital" and it was "confident that the distribution utilities will continue to find cost-efficiencies due to the high-powered incentives of K-bar and will be able to offset any increased capital funding needs by realizing efficiencies in other areas, whether capital or O&M". It observed that, in the second performance-based term, "several distribution utilities spent less on capital than the average historical capital additions assumed in the K-bar mechanism", and that over that period the utilities generally met or exceeded their approved return on equity: *Third Term Decision* at paras 208-209.

[45] In concluding its analysis of the parameters for the third performance-based rate term, the Commission assessed whether the rates established under the plan as a whole will be "just and reasonable" and whether they will provide the utilities with "a reasonable opportunity to recover their prudently incurred costs and earn the approved rate of return over the term of the plan". The Commission concluded that the third term performance-based rate plan would do so, noting the incentive structure of the various plan components but also their interdependency, saying that the "parameters of each of the PBR 3 plan components should therefore not be viewed in isolation from other plan components": *Third Term Decision* at paras 431, 435. With respect to basing the Type 2 supplemental capital funding on "historical levels" of capital investment, it said that at "these levels, the utilities have generally demonstrated that they can provide safe and reliable service to their customers, without detriment to their opportunity to recover their costs and earn a fair return": *Third Term Decision* at para 440.

Analysis

[46] The assessment of whether the use of historical averages in the K-bar calculation denied the appellants a reasonable opportunity to recover their prudently incurred capital costs, including a fair return on equity, begins with the context and functional purpose of that decision. As set out previously, the Commission adopted performance-based regulation to reduce regulatory burden and to lower costs for customers by incentivizing the utilities to be more efficient, including by avoiding over-investing in capital. It did so while recognizing the core objectives of safe and reliable service and ensuring utilities a reasonable opportunity to recover their prudent costs and earn a fair return. The Commission distilled these objectives into its five principles of performance-based regulation.

[47] The Commission's challenge in any given case is how to operationalize these objectives and obligations; here, how to structure the funding mechanism for supplemental capital to accomplish fair rates for customers while still ensuring the utilities a reasonable opportunity to recover their costs and earn a fair return on equity, objectives that are, to a certain degree, in tension with one another. That challenge is compounded by the prospective nature of utility rate regulation: the Commission approves rate plans and rates for a future period of time based on its anticipation of what will achieve its regulatory objectives, including in relation to selecting appropriate plan structures, mechanics and inputs.

[48] In exercising its regulatory function, the Commission must always, of course, remain within the statutory authority granted by the legislature:

> 119(1) Each owner of an electric utility must prepare a tariff in accordance with this Act and the regulations and apply to the Commission for approval of the tariff.
>
> …
>
> 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) <u>the tariff is just and reasonable</u>,
> >
> > …
>
> (3) <u>A tariff that provides incentives for efficiency is not unjust or unreasonable simply because it provides those incentives</u>.

(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 <u>a tariff approved by it must provide the owner of an electric utility with a reasonable opportunity to recover</u>

(a) <u>the costs and expenses associated with capital related to the owner's investment in the electric utility</u>, 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) <u>a fair return on the equity of shareholders</u> of the electric utility as it relates to the investment, and

(v) taxes associated with the investment,

<u>if the costs and expenses are prudent</u> and if, in the Commission's opinion, they provide an appropriate composition of debt and equity for the investment,

(b) <u>other prudent costs and expenses</u> associated with isolated generating units, energy storage resources, 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…

[emphasis added]

Electric Utilities Act, ss 119, 121-122.

[49] In the *Third Term Decision*, the Commission made a series of interrelated decisions which, in its view, operate collectively to satisfy its statutory obligations and are consistent with the principles of performance-based regulation. The appellants accept many of those decisions, including the adoption of performance-based regulation, the decision to set the going-in rates for the third term using a cost of service proceeding (which, for ENMAX, concluded with a negotiated

settlement), the quantum of the going-in rates for each of the appellants, and an annual I-X adjustment to reflect inflation and expected productivity.

[50] The appellants further acknowledge that the use of adjusted historical averages as the basis for the comparator in step 2 of the K-bar calculation for Type 2 supplemental capital funding is not inherently problematic, they did not seek permission to appeal that approach in the second performance-based regulation term, and, with the exception of ENMAX, they met or exceeded their approved return on equity throughout the second term.

[51] Nonetheless, the appellants argue that the Commission's decision to use only historical averages as the basis for the K-bar comparator for the third term was speculative and inconsistent with the evidence. They say the Commission had no evidentiary basis for its assertion that the appellants' anticipated capital additions would be in line with their historical averages. The Commission simply made an "assumption" that future capital additions will track historical additions such that the utilities will have a reasonable opportunity to earn an approved rate of return: *Third Term Decision* at para 201. The appellants point to evidence of new, significant multi-year capital projects they have planned for the third term that they say will not be funded using only a historical comparator. The appellants submit the Commission has deprived them of the reasonable opportunity to recover and earn a fair return on their prudent costs of capital, contrary to s 122(1) of the *Electric Utilities Act*.

[52] The suggestion that the Commission made a speculative and unsupported decision to use historical averages in calculating Type 2 capital funding mischaracterizes the Commission's reasons and analysis.

[53] The Commission identified and appreciated its statutory obligation to approve rates that provide the appellants a reasonable opportunity to recover their prudent costs and earn a fair return. The Commission weighed the evidence and information before it in light of its experience and expertise to determine whether to rely solely on adjusted historical averages, or to also incorporate the utilities' forecast capital additions. The Commission explained that it chose historical averages because of the success of that methodology through the second term; due to the problems with forecasting in general and especially over a long period of time; and, to protect the incentive structure of performance-based regulation. It relied as well on the overall approach to capital funding applicable to the third term, including the funding for capital additions included in the adjusted base rate itself, and the freedom given to utilities to efficiently manage their capital expenditures and operational budget. It pointed to the reduced regulatory burden – particularly when compared with the capital tracker mechanism used in the first term of performance-based regulation – that arises from providing an envelope of funding based on historical averages, rather than funding projects on a project-by-project basis.

[54] In short, the Commission did not make an extricable error of law. It knew what the law required in relation to the appellants' rates and it made a reasoned determination regarding the K-bar comparator that would allow it to best meet those requirements given the evidence and

information before it. How the Commission applied the legal requirements to the evidence and information depends on assessments of fact and policy to which this Court owes deference.

[55] The selection of historical averages must also be considered in light of the Commission's significant prior experience addressing supplemental capital funding. As previously outlined, the *Third Term Decision* is one in a series of decisions on this issue. The Commission explicitly references and relies on the "concepts and terminology" from its earlier decisions: *Third Term Decision* at para 173. That includes the Commission's earlier observation about the "considerable flexibility" enjoyed by utilities with respect to their capital expenditures, and the regulatory burden and reduced incentives associated with funding capital projects on a project-by-project basis: *Second Term Decision* at paras 152, 196, 211-214. Those considerations, arising from the Commission's expertise and experience on this issue with these utilities over multiple years and rate periods, properly informed its analysis of the record, and reasonably support its conclusion.

[56] The appellants rely heavily on the Commission's statement that its decision is based on an "assumption" that if the appellants "are provided with a level of supplemental capital commensurate with their actual experience during the prior PBR term" they will have a reasonable opportunity to recover their prudent costs and earn a fair rate of return: *Third Term Decision* at para 201. They say it is an error of law to make this type of an assumption.

[57] We disagree. The Commission's use of the word "assumption" does not alter the substance of what it actually did – which was draw an inference from the record relying in part on past experience, the totality of funding available to the appellants, and the overall structure of performance-based regulation. As earlier observed, the Commission's task is prospective – it is deciding what will happen, not what has happened. A decision-maker making that type decision needs to rely on experience and expertise to make a reasoned assessment – a so-called assumption – about what is likely to occur given the evidence and information before it. The Commission did not err in making such an assessment here.

[58] The appellants also rely on the evidence before the Commission in the underlying proceeding, and the evidence and information accepted by the Commission in approving the 2023 cost of service rates, showing they were planning significant new multi-year capital projects that would require funding throughout the upcoming term. They argue those capital projects did not replicate historical capital additions and thus could not, logically, be reflected in updated averages of their historical capital additions. As a result, the appellants submit, using only adjusted historical average additions as the basis for the comparator in the Type 2 capital K-bar calculation cannot sufficiently fund their planned capital additions.

[59] Fortis identifies its advanced metering infrastructure, distribution voltage management, and wildfire mitigation programs as new capital projects not reflected in the five-year average of its actual capital additions from 2018-2022. In the 2023 cost of service review, Fortis forecast its capital additions for 2023 at $482.9 million, of which the Commission approved $3.7 million for the advanced metering program, $7.8 million for its distribution voltage management program,

and $11 million for its wildfire management program: *ATCO Electric Ltd FortisAlberta Inc 2023 Cost-of-Service Review*, AUC Decision 26615-D01-2022 (28 July 2022) at paras 236, 260, 262, 284, 290 [*2023 Cost of Service Review Decision*].

[60] ATCO identifies its grid modernization project as a new capital project not reflected in historical averages. In the 2023 cost of service review, ATCO forecast its capital additions at $307.6 million, of which the Commission approved $36.1 million related to the grid modernization project: *2023 Cost of Service Review Decision* at paras 314, 373-374.

[61] ENMAX's rebasing was accomplished through a negotiated settlement, but it similarly points to evidence that its 2023 forecast capital costs included new capital additions to replace aging assets at or near the end of their life, and that like Fortis, it too undertook an advanced metering infrastructure project involving approximately $30 million of capital additions per year.

[62] We do not agree with the appellants that the existence of these forecast capital additions is sufficient to establish the Commission made an error of law. The evidence highlighted by the appellants in relation to these projects reflects only a narrow band of the appellants' forecast capital additions and lacks general and historical context. It does not provide insight into their other planned capital additions for 2024 to 2028 or their flexibility in relation to those additions. Nor does it provide information about the mix of historical actual capital additions over the comparator period from 2018 to 2022, including whether any of those additions were unusual or did not continue. The evidence highlighted to us by the appellants does not, in and of itself, establish the logical proposition asserted: that because certain of their capital additions are significant and new, using only historical averages as the basis for the comparator in the Type 2 capital K-bar calculation deprives the utilities of the opportunity to recover their prudent costs or earn a fair rate of return on equity.

[63] For example, ATCO points to the evidence before the Commission that only the first year of its grid modernization project is included in the rate base, because the *2023 Cost of Service Review Decision* only approved the $36 million capital addition associated with the project's first year. Further, because the grid modernization project is new, it is largely excluded from the historical averages used to calculate the step 2 comparator. ATCO submits this evidence shows it will be underfunded for its grid modernization project by $27 million to $37 million per year, since those amounts are included in neither the adjusted base rate nor the Type 2 capital K-bar calculation.

[64] This evidence is, however, incomplete and partial. As earlier noted, ATCO's forecast capital additions for 2023 were $307.6 million. Its forecast capital additions for 2022 were actually higher, at $353 million: *2023 Cost of Service Review Decision* at para 314. The grid modernization project is approximately 12% of the forecast capital additions for 2023. Yet, ATCO did not direct this Court to any evidence about the broader picture that was before the Commission. It did not identify evidence about its flexibility, or lack thereof, in relation to its other planned capital additions. It did not identify evidence about whether the second term of performance-based

regulation similarly involved new or atypical capital additions for ATCO, or whether all capital additions in the second term were routine. It did not identify evidence about whether, or how many, capital projects from the second term continued into the third term. In essence, ATCO asks this Court to look at its evidence showing the annual cost of the grid modernization project in isolation and to accept that as sufficient to demonstrate "that a capital funding methodology based on historical actual capital additions from the PBR2 term would result in ATCO being underfunded for the [grid modernization project] by approximately $27M-$37M in capital additions per year". But looking at the forecast for one project, without any other information about ATCO's capital additions – general, historical and forecasted – does not justify that conclusion. It does not establish, or even meaningfully illustrate, the appellant's claim that by excluding forecasts from the K-bar calculation the Commission precluded them from having a reasonable opportunity to earn a fair return.

[65] Similar observations can be made about the examples relied on by Fortis and ENMAX, neither of whom cited evidence or information to this Court about their capital additions beyond the specific examples of new projects being undertaken during the third term of performance-based regulation.

[66] The appellants suggest the Commission effectively ignored the previous determinations it made in setting the 2023 rates during rebasing. They emphasize the Commission determined the capital additions associated with one year of the proposed multi-year projects were reasonable. The appellants challenge the Commission's reasoning dismissing the significance of the rebasing proceedings, suggesting it elides the importance of the Commission's assessment of the business plans and forecasts they provided during the rebasing process. The Commission's point was that including these projects in the appellants' revenue requirement for rebasing does not preclude the Commission from also deciding to calculate K-bar using historical averages; they are distinct inquiries involving distinct considerations.

[67] It was open to the Commission to find, on the record before it – a record that includes its previous inclusion of the appellants' proposed capital additions for 2023 in the appellants' rebased base rates – that the use of updated historical averages in the K-bar calculation would provide the appellants a reasonable opportunity to recover their prudent costs and earn a fair return on equity. The Commission did not err in concluding that its earlier decisions on rebasing did not preclude it from making that finding. It can be logically true that the new multi-year capital projects are prudent and reasonable, and that they will be sufficiently funded through the envelope of supplemental Type 2 capital funding available in the third performance-based regulation term.

[68] The role of this Court is to ensure the Commission makes correct decisions on questions of law and jurisdiction. The Commission made no error of law or jurisdiction here. It identified and appreciated the statutory constraints on its regulation of the appellants' rates. It weighed the evidence and information before it to assess how to comply with those statutory constraints given the particular facts and circumstances related to the Type 2 capital K-bar calculation. It explicitly

considered the sufficiency of the funding received by the appellants, and the overall fairness of the rates resulting from its decision.

[69] The appellants have identified no basis for us to interfere with the Commission's decision to use average historical capital additions in step 2 of the supplemental capital K-bar calculation.

Defining the productivity X factor in the supplemental capital K-bar calculation

[70] As described, the third term Type 1 supplemental capital K-bar calculation compares the funding available for capital projects in a utility's adjusted base rate (step 1) with a notional revenue requirement based on the utility's average historical capital additions from 2018 to 2022 (step 2). Both parts of the comparison incorporate adjustments to account for inflation, expected productivity gains, and customer growth:

a) For step 1, the capital-related portion of the 2023 going-in rates is multiplied by inflation less expected productivity gains, I-X, and a customer growth escalator is applied, to adjust for each year from 2024 to 2028.

b) For step 2, the capital additions for each of 2018 to 2022 are converted to 2023 dollars using an I-X multiplier and growth escalator, and an average of annual capital additions is calculated in 2023 dollars. That average is then adjusted for each year from 2024 to 2028 through again applying I-X and a growth escalator. The notional revenue requirement is the incurred capital costs associated with the adjusted average capital additions.

[71] For the purposes of the foregoing comparison, the Commission specified a lower productivity X factor than it specified for the main base rate adjustment: *Third Term Decision* at para 221. As a result, the step 1 value, which is supposed to reflect the funding available for capital additions in the adjusted base rate, does not match the funding for capital additions the utility will actually receive through the adjusted base rate. The step 1 value is higher because a lower productivity adjustment is applied.

[72] ENMAX submits that this results in an error of law, because the result is "an artificially inflated number" for step 1 "that overstates the actual capital funding the [distribution utility] receives under the base" rate. This, in turn, "artificially reduces K-bar funding, depriving utilities of their right to a reasonable opportunity to recover their prudent costs". It argues the decision to use a lower X factor was driven by the Commission's improper focus on making "rates more affordable".

[73] This argument ignores the fact that the same, lower productivity X factor is used for both parts of the K-bar comparison and misstates the basis for the Commission's decision. The Commission did not use a different X factor in the K-bar calculation out of a general desire to reduce consumer rates. Rather, it adjusted the X factor because it identified a distorting effect

associated with using the X factor to adjust both the base rate in step 1 and the revenue requirement based on historical capital additions in step 2. As explained by the Commission:

> …an X factor performs two distinct functions in the K-bar accounting test. In the first step of the accounting test, an X factor determines the amount of revenue provided under I-X – that is, a higher X factor will result in lower revenue and a lower X factor will result in a higher revenue. In the second step, an X factor is used to escalate historical average capital additions to current year values. The effect of an X factor in the first step of the accounting test outweighs the effect of it in the second step by an order of magnitude.
>
> [emphasis added]
>
> *Third Term Decision* at footnote 268.

The Commission explained that unless the productivity X factor is adjusted, "the workings of the accounting test would increase the K-bar amount with the paradoxical result that such increase to K-bar would, for the most part, offset the rate reduction implied by the X factor premium benefit-sharing provision" [emphasis added]: *Third Term Decision* at para 221.

[74] Whether adjusting the X factor for the K-bar calculation deprives the appellants of a reasonable opportunity to recover their prudent costs and earn a fair return depends, therefore, on whether the Commission erred in identifying the accounting effects of using the X factor for both parts of the K-bar comparison, and in then adjusting the X factor to ameliorate those accounting effects. At the hearing, counsel for ENMAX declined to make submissions on whether the Commission erred in describing the distorting effect of applying the X factor to both parts of the comparison.

[75] In the absence of such submissions, this Court has no basis on which to conclude that the Commission made a reviewable error in deciding to use a lower productivity X factor for the Type 2 capital K-bar calculation.

Defining Type 1 capital

Third Term Decision

[76] As mentioned, for the third performance-based regulation term, the Commission continued its general approach of allowing utilities to apply for capital tracker funding for extraordinary "Type 1" capital expenditures. The Commission rejected the distribution utilities' request, including the appellants', for the eligibility criteria for Type 1 funding to be relaxed. The utilities pointed out that no project had qualified for Type 1 funding during the second term. ENMAX argued, "there is no value in an incremental capital funding mechanism that is not attainable": *Third Term Decision* at para 226.

[77] The Commission did not find this argument persuasive. Type 1 funding was intended to be available only for “projects of an extraordinary nature”. The Commission had evaluated the two applications made during the second term and determined that neither met the criteria for Type 1 funding. In the Commission’s view, “the Type 1 capital tracker mechanism worked as intended”: *Third Term Decision* at paras 228-229.

[78] The Commission pointed out that funding for capital projects was available through the adjusted base rate and the Type 2 funding envelope. It also noted that a utility may access Z factor funding for capital expenditures “associated with exogenous events outside of the control of the distribution utility”: *Third Term Decision* at para 232.

[79] The Commission did not agree that any project not funded through the base rate or K-bar should “automatically, in [and] of itself, qualify … as extraordinary”, as the utilities “are expected to manage their total capital and O&M costs as a whole, rather than request incremental funding for individual projects”: *Third Term Decision* at para 237. Type 1 funding should be reserved for “only truly extraordinary expenditures”, with the majority of projects funded through mechanisms that reflect the incentives of performance-based regulation: *Third Term Decision* at para 246. The criteria proposed by the utilities were “overly broad” and would be “meaningless”, applying “to virtually all distribution utility projects”: *Third Term Decision* at para 247. Leaving the matter to the discretion of the Commission would create subjectivity and uncertainty: *Third Term Decision* at para 248. The Commission characterized Fortis’s proposed major projects funding supplement similarly as having the tendency to “drastically reduce the incentive to manage costs under I-X and K-bar”: *Third Term Decision* at para 306.

[80] The Commission agreed with the interveners that a broader funding mechanism could result in a utility receiving funding for a project that “either offsets or eliminates the need for projects that were included in the K-bar funding envelope”. A broader Type 1 mechanism “runs the risk that distribution utilities could pursue methods of shifting expenditures that would otherwise be funded through I-X and K-bar to Type 1 capital”. Since those expenditures would then be recovered from customers, it would allow the utilities to earn a higher return on equity without introducing efficiencies and would lead to higher prices for customers: *Third Term Decision* at para 254.

[81] The Commission expanded the criteria for Type 1 funding insofar as it also permitted additional funding for expenditures directly caused by laws related to net-zero objectives. The Commission thus specified the criteria for Type 1 funding as:

> (i) The project must be extraordinary and not previously included in the distribution utility’s rate base.
>
> (ii) The project must be required by a third party, or otherwise directly caused by applicable law related to net-zero objectives.

(iii) The project cost must have a material effect on the distribution utility.

Third Term Decision at para 230.

Analysis

[82] ENMAX and ATCO – with whom Fortis agrees – ask this Court to find the Commission erred in law by establishing unduly restrictive eligibility criteria for Type 1 funding. They submit the criteria fail to provide them a reasonable opportunity to recover their costs and earn a fair return. They rely on three Commission decisions denying Type 1 funding to illustrate the "unreasonably restrictive nature of the test".

[83] In particular, the appellants point out that in those decisions, the Commission denied Type 1 funding in part because capital projects similar to those proposed by the applicant in each case had been previously included in the applicant's rate base: *AltaGas Utilities Inc Type 1 Capital Tracker True-Up – Etzikom Lateral Project,* AUC Decision 25608-D01-2020 (16 October 2020) at paras 33-35; *ENMAX Power Corporation Type 1 Capital Tracker – Green Line Light Rail Transit Project*, AUC Decision 26589-D01-2021 (24 November 2021) at paras 34-35; *FortisAlberta Inc Type 1 Capital Tracker Application*, AUC Decision 29513-D01-2025 (25 April 2025) at paras 48-52.

[84] The appellants submit the requirement that the project was "not previously included in the distribution utility's rate base" makes the Type 1 test impossible to meet. They submit all capital projects undertaken by a utility will involve some purpose, cost, asset or facility that the utility previously deployed or included in its rate base and, consequently, in every case a proposed capital project will fall outside the criteria for Type 1 funding. The appellants submit it is contrary to the legal requirement of just and reasonable rates to include a category of funding that no utility will ever, in actuality, be able to access. Further, it contradicts the Commission's own recognition that funding ought to be available for extraordinary capital expenditures.

[85] The appellants have not established the Commission made an error of law in its treatment of Type 1 funding. The Commission explained Type 1 funding should be reserved for "extraordinary" expenditures to ensure most projects are funded through mechanisms that reflect the incentives of performance-based regulation. Further, it made a logical and reasonable assessment that the relationship between a proposed capital project and the previous capital expenditures of a utility – its rate base – is salient to whether a proposed project is extraordinary. When a company has a documented record of capital expenditures, it makes sense to assess a proposed project against those prior expenditures to assess whether the proposed project is, in fact, extraordinary.

[86] It could be, as the appellants suggest, an error for the Commission on a particular application to find that a project has been previously included in a rate base in circumstances where that project has only a remote or tangential relationship to the utility's prior capital expenditures.

That sort of error is, however, one of application, not law. It does not establish the Commission erred by requiring, as a general matter, that extraordinary projects not be of a type previously included in a utility's rate base.

[87] We also cannot accept the appellants' assertion that three prior decisions by the Commission over several years give rise to an inference that the Commission will never approve a project for Type 1 funding. Three decisions cannot establish that conclusion is inevitable. The appellants effectively ask this Court to find that the Commission erred or acted unreasonably in denying those Type 1 applications, yet no application for permission to appeal them was or has been advanced. This is a collateral attack and the merits of those earlier decisions cannot properly be contested in the context of this appeal.

[88] This Court finds no reviewable error in the Commission's specification of the criteria for Type 1 supplemental capital funding.

Adjusting the Fortis productivity X factor to reflect business risks associated with providing service to rural electrification associations

[89] In calculating the productivity X factor applied to adjust a utility's base rate for the third term of performance-based regulation, the Commission continued to apply a "stretch factor" to reflect expected efficiency gains beyond those reflected in industry historical growth studies. The Commission explained it was reasonable to expect productivity growth under performance-based regulation to be better than industry historical growth: *Third Term Decision* at paras 148, 154.

[90] Before the Commission, Fortis argued its ability to exceed average industry productivity growth was negatively impacted by earlier decisions that prevented it from recovering costs related to the use of its distribution system by rural electrification associations. As a result, Fortis argued that no stretch factor should be applied to its productivity X factor adjustment.

[91] The background for this argument is a statutory framework and certain adjudicative decisions that resulted in Fortis being required to provide rural electrification associations with access to its distribution system while only being able to recover the costs associated with that access under the terms of integrated operation agreements or arbitration, as opposed to through distribution rates regulated by the Commission: *Equs Rea Ltd v Alberta (Utilities Commission)*, 2023 ABCA 142 at paras 23, 27, 39-40, 43-44, 53, 108-110, 120-125 [*Equs Rea*]; *Roles, Relationships and Responsibilities Regulation*, 2003, Alta Reg 169/2003 (3R Regulation), ss 4, 9.

[92] Some of the integrated operation agreements Fortis has in place do not include any cost recovery. For the largest rural electrification association in its service area, Fortis was unable to agree on cost recovery. That issue was referred to arbitration, and the arbitrator decided on a single, one-time connection fee that did not account for ongoing operation or maintenance. As a result, there is a difference between the costs removed from Fortis's distribution rates by the Commission to reflect its service to rural electrification associations and the costs it is able to recover from the

rural electrification associations. There are "approximately $10 million of costs that Fortis incurs each year to own and operate its distribution system in accordance with its statutory mandate that are not recoverable from either Fortis customers or the REAs, even though the prudence of those costs has not been challenged": *FortisAlberta Inc v Alberta Utilities Commission*, 2025 ABCA 78 at paras 9-11 [*Fortis 2025*].

[93] From Fortis's perspective, the gap in its ability to recover costs associated with serving rural electrification associations acts as a *de facto* stretch factor, such that its productivity X factor ought to exclude the stretch factor applied to other distribution utilities.

[94] In *Fortis 2025*, this Court explicitly stated the Commission could consider the business risks associated with Fortis having an obligation to serve rural electrification associations without being able to fully recover the costs of doing so. While this Court dismissed Fortis's appeal of a Commission decision refusing to adjust a component of Fortis's rates because of this issue, it also said the Commission was not legally precluded from "considering business or regulatory risk arising from circumstances relating to the recovery, or non-recovery, of REA Costs". An earlier statement of this Court in *Equs Rea* that there is "no sound reason why FortisAlberta's customers should subsidize the members of rural electrification associations" does not "preclude any impact whatsoever on Fortis's customers arising out of changes to the business and regulatory environment regarding recovery of REA Costs": *Fortis 2025* at para 25-27; *Equs Rea* at para 23.

[95] Nowhere in its explanation for why the continued application of a stretch factor is warranted does the Commission address Fortis's submissions or evidence on the impact of its obligation to serve rural electrification associations, nor does it explain its apparent decision to reject Fortis's submissions on this point: *Third Term Decision* at paras 148-163.

[96] Failing to provide sufficiently intelligible reasons is an error of law: *Custom Metal Installations Ltd v Winspia Windows (Canada) Inc*, 2020 ABCA 333 at para 32; *R v Nahanee*, 2022 SCC 37 at para 59(ii). The simple underlying rule is that if, in the opinion of the appeal court, the deficiencies in the reasons prevent meaningful appellate review of the decision, then an error of law has been committed: *R v Sheppard*, 2002 SCC 26 at para 28.

[97] Here, Fortis asked the Commission to consider its particular business risks in determining its stretch factor. It adduced evidence in support of its position. Its submissions addressed an issue relevant to the proper determination of its rates. The Commission rejected Fortis's argument without explanation. Its reasons, when read in the full context of the record, afford no basis for meaningful appellate review.

[98] It is not for this Court to say how the Commission should respond to Fortis's submissions, but the Commission could not simply ignore them. Doing so was an error of law.

Ensuring public accessibility and accountability of Alberta Utilities Commission decisions

[99] Commission proceedings involve complex issues engaging intersecting concepts of law, economics, accounting, business and public policy. The parties, counsel and witnesses who appear before the Commission, and the panel members who conduct Commission proceedings, generally have subject matter experience and expertise, and thus familiarity with the relevant concepts, and with their application to the particular questions the Commission is considering. For the most part, Commission decisions are written for, and read by, subject matter experts. Perhaps as a consequence, Commission decisions have always relied heavily on acronyms, initialisms and shorthand terms, and have done so without apparent difficulty for the participants in Commission proceedings or the Commission itself.

[100] However, the audience for Commission decisions is not limited to subject-matter experts. All Albertans consume energy and are affected by Commission decisions. Given their impact and significance, Commission decisions should be written in as straightforward a manner as possible such that a lay person or journalist, for example, can read and understand them relatively easily. The reasonableness of an administrative decision can be assessed through the extent to which it is "transparent, <u>intelligible</u> and justified" [emphasis added]: *Vavilov* at para 15.

[101] The Commission cannot change the inherent complexity of the topics it addresses, but reducing its reliance on acronyms and initialisms, and using more descriptive conceptual shorthand, would improve the accessibility of its decisions for those not immersed in the field or present at a proceeding. The Appendix to the *Third Term Decision* contained over 30 acronyms, initialisms and abbreviations, many of which were not terms used across the industry or in other decisions, and the meaning of which was not apparent from the term itself. The result was to make the decision more difficult to understand without any corresponding benefit. For example, the decision defined Fortis's specific capital funding proposal, its "major projects funding supplement", as MPFS in paragraph 235. It discussed that proposal briefly in paragraphs 255 and 256 (where it described it as the "MPFS funding mechanism") and again in paragraph 266 (where it called it a "MPFS mechanism") and then made its decision rejecting it in paragraphs 305-307, where it defined it for a second time, and referred to it only as MPFS. Removing the initialism would have created simplicity and consistency and been easier for the average reader to follow. It would have added about 50 words to a decision of many thousands.

[102] The Commission could improve the intelligibility of its decisions by limiting acronyms and initialisms to terms in ordinary use (e.g., km) or that occur commonly across proceedings (e.g. PBR), and by using defined terms that communicate their basic purpose or meaning (e.g., ordinary capital funding supplement instead of K-bar). Doing so would promote the accountability and accessibility of its regulatory activities for Albertans without increasing the Commission's regulatory burden.

Conclusion

[103] The appeal is dismissed and the decision of the Commission is confirmed, except with respect to the issue of the Commission’s failure to consider Fortis’s argument regarding the use of a stretch factor. The decision on that issue is vacated and referred back to the Commission for further consideration and redetermination.

Appeal heard on January 15, 2026

Memorandum filed at Calgary, Alberta
this 31st day of July, 2026

Woolley J.A.

Friesen J.A.

Shaner J.A.

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