REGULATORY LAW CHAMBERS

ENERGY REGULATORY REPORT

This monthly report summarizes matters under the jurisdiction of the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC") and the Canada Energy Regulator ("CER") and proceedings resulting from these energy regulatory tribunals. For further information, please contact a member of the RLC Team.

Regulatory Law Chambers ("RLC") is a Calgary based boutique law firm, specializing in energy and utility regulated matters. RLC works at understanding clients' business objectives and develops legal and business strategies with clients. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

IN THIS ISSUE:

ALBERTA COURT OF APPEAL

ATCO Electric Ltd. v Alberta (Utilities Commission), 2019 ABCA 417

Rates - Information Technology Costs

In this decision, ATCO Electric Ltd. and ATCO Gas and Pipelines Ltd. (the "Applicants") sought permission to appeal an AUC decision that allowed only part of the Applicants' information technology ("IT") service costs. Permission to appeal was denied.

Factual Background

Prior to December 1, 2014, the Applicants' IT services were provided by an unregulated entity called ATCO I-Tek. I-Tek and the Applicants were owned by the same parent companies, collectively called "ATCO" in the AUC decision. ATCO decided to re-evaluate its means of obtaining IT services. Ultimately, it decided to sell I-Tek. It invited bids for IT service provision, with the requirement that bidders also had to offer to buy I-Tek.

In August 2015, a global IT company called Wipro bought I-Tek and entered into agreements to provide IT services to ATCO and the Applicants. The Applicants' IT service agreements were the subject of the AUC proceedings.

AUC's Decision

In determining whether the IT service pricing resulted in just and reasonable rates, the AUC considered the Applicants' sourcing strategy and the structure of the bidding process. The AUC found that the decision to couple the sale of I-Tek with the IT service contract limited the pool of potential bidders and therefore raised the price of IT services.

The appropriate remedy was to make a partial price reduction. After considering the sourcing strategy, the bid process, the evidence of fair market value, and the structure of the IT service agreements, the AUC reduced first year expenditures by 13%, with a follow-on effect on subsequent years. The AUC imposed a glide path to reduce weighted average prices by 4.61% per year in years 2 through 10.

Test for permission to appeal an AUC decision

The Court outlined the test for permission to appeal, noting where the proposed question on appeal goes to "the core of the AUC's mandate and expertise", the Court will be highly deferential in its review and will apply a high bar to obtaining permission to appeal. It further noted that this case involved ratemaking, which "is at the heart of a regulator's expertise."

Grounds of appeal

Ground One

On the first ground, the Applicants alleged that the AUC made certain findings based on no evidence, or no credible and reliable evidence, or contrary to the only evidence on record, and that any of these errors is an error in law.

The Court noted that the Applicants bore the burden of showing that their proposed rates were just and reasonable, and that the AUC's conclusion that they failed to meet this burden had significant factual and evidential components.

The Court found that the AUC was aware of and considered all the evidence before it, as demonstrated by its summaries of evidence at the beginning of each section of its analysis. The Court was satisfied that the AUC did not overlook evidence and that it interpreted and assessed the evidence, as it was entitled to do.

Whether the evidence was credible or reliable was a question of fact for the AUC to decide. Only in extreme cases can decisions on credibility or reliability amount to questions of law. The Court was not satisfied that this was such a case.

The Court was not satisfied that the errors alleged under this ground raised questions of law.

Ground Two

The Applicants submitted that the AUC has a legislated obligation to ensure that regulated utilities have a reasonable opportunity to recover reasonably and prudently incurred costs and that the AUC failed to fulfill its obligation in this case. They argued that, if the decision to incur the costs was prudent and reasonable, they must be given the opportunity to recover their costs — implicitly, meaning the entirety of their claimed costs.

The Court noted that the AUC is not bound to accept or reject a claim for cost recovery in its entirety. It is empowered to determine which costs are "appropriate". The Court further noted that the AUC was not satisfied that the Applicants' IT services sourcing strategy was prudent. It found that the Applicants did not identify any extricable legal error in the AUC's handling of certain topics, and did not satisfy the Court that the high bar for permission to appeal was met.

Ground Three

The Court noted that the AUC was aware that the coupling of the I-Tek sale with IT service sourcing created two different risks of cross-subsidization: either the ratepayers could effectively subsidize the I-Tek sale (if they were required to pay for IT services at an inflated rate), or the shareholders of the ATCO entities could effectively subsidize the ratepayers (if the entire actual cost of IT services were not passed on to the ratepayers).

The AUC found that the evidence suggested some cross-subsidization in the first sense, but the coupling of sale and services impaired its ability to assess its extent. This improper influence on the service pricing contributed to the AUC's conclusion that the IT service prices were not "just and reasonable."

The Applicants did not attack this finding. Rather, they alleged error in connection with the second type of cross-subsidization. They first asserted that the AUC failed to protect against impermissible cross-subsidization of ratepayers by shareholders when it denied full recovery of IT service costs.

The City of Calgary (“City”) had asked the AUC to subtract a portion of the ATCO I-Tek sale price from the amount recoverable under the IT service agreements. The Applicants opposed, claiming impermissible cross-subsidization. The Court noted that the AUC chose not to apply the City's approach, and the AUC, therefore, did not need to consider this version of cross-subsidization.

The Court found that the Applicants had not identified any error by the AUC.

Secondly, the Applicants suggested that the effect of the AUC's decision was to allow impermissible cross-subsidization in the second sense. The Court noted again that the AUC found some indication of cross-subsidization in the first sense. It further noted that it struggled to see how there could be cross-subsidization in both directions simultaneously. Ultimately, the Court noted that it was unable to characterize the suspected effect of a decision as an error in law or jurisdiction.

<u>Conclusion</u>

The Court found that the Applicants raised no issues of pure law or jurisdiction. Permission to appeal was denied.

ALBERTA ENERGY REGULATOR

Directive 056 Updated and New Well Applications Moved to OneStop, AER Bulletin 2019-22

Bulletin - Directive 056

On October 3, 2019, the AER released a new edition of *Directive 056: Energy Development Applications and Schedules* that came into effect on October 17, 2019.

Section 7.8 has been updated as follows:

- The Lahee classification system has been replaced with a new one that distinguishes between exploration and exploitation activity while taking into account other unique well types drilled in Alberta.
- The applicability of the "confidential below" designation will now only be assessed after a well is drilled.
- Drill cutting sample requirements have been updated to align with the new classification system.

Effective October 17, all applications for new well licences must be submitted through OneStop, and the *Directive 056* changes will be incorporated into OneStop.

As a result of the transition of these well applications to OneStop, the Digital Data Submission ("DDS") system stopped accepting new well applications as of 5:00 p.m. on October 10, 2019.

<u>OneStop Prerequisites</u>

To submit a well licence application through OneStop, you will need

- a valid business associate ("BA") code, and
- a valid DDS system account (needed to log in to OneStop).

In addition, the DDS administrator must assign new roles to your DDS users, including consultants submitting applications on your behalf. The new OneStop roles are as follows:

- Submit Wells – enables users to access OneStop and submit applications; it includes the Save Application role
- Save Wells – enables users to access OneStop and save draft applications; it includes the Search Submission role
- Search Wells – enables users to access OneStop; users cannot save or submit applications

IL 83-02 and ID 96-03 Rescinded, AER Bulletin 2019-25

Bulletin

The AER has determined that the following regulatory documents are no longer necessary, and they are now rescinded:

<u>IL 83-02</u>

Informational Letter 83-02: Annual Reservoir Review for Gas Pools has now been rescinded for the following reasons:

- The AER no longer releases general bulletins to request the submission of gas pool information.
- Requirements related to gas pool production submissions are found in *Directive 017: Measurement Requirements for Oil and Gas Operations* and information regarding the conservation of gas pools in Alberta is submitted in accordance with unit 2 of *Directive 065: Resources Applications for Oil and Gas Reservoirs*.

<u>ID 96-03</u>

Interim Directive 96-03: Oilfield Waste Management Requirements for the Upstream Petroleum Industry has now been rescinded for the following reason:

- These requirements are found in Directive 058: Oilfield Waste Requirements for the Upstream Petroleum Industry.

***New Edition of Manual 011*, AER Bulletin 2019-23**

Bulletin - Manual 11

On October 7, 2019, the AER released a new edition of *Manual 011: How to Submit Volumetric Data to the AER*. Changes were made to the activity codes in appendix 1 and to the wording around acid gas in appendix 9.

These changes make the manual consistent with the latest editions *of Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* and *Directive 017: Measurement Requirements for Oil and Gas Operation*, which were released in December 2018 (see *Bulletin 2018-37* and the Providing Information > By Topic > Methane Reduction page on the AER website).

***Request for Regulatory Appeal by Canadian Natural Resources Limited, Rejection of Application No. A10081833; Licence of Occupation 180965 Location: 03-27-065-05W4 to 16-21-065-06W4M*, AER Regulatory Appeal No.: 1916881**

Regulatory Appeal

In this decision, the AER determined that a hearing into the Regulatory Appeal be held as the legislative tests were met.

Canadian Natural Resources Limited ("CNRL"), request for regulatory appeal related to the rejection of an Application in which CNRL is the proponent for the requested Licence of Occupation.

The AER will be asking that the Chief Hearing Commissioner appoint a panel of hearing commissioners to conduct a hearing of the Regulatory Appeal.

***Request for Regulatory Appeal by Ervin and Rita Callan ConocoPhillips Canada Resources Corp. Application No.: 1896604; Approval No.: WM 208 Location: 07-083-06 W4M*, AER Regulatory Appeal No.: 1917192**

Regulatory Appeal

In this decision, the AER considered Ervin and Rita Callan's request under Section 38 of the *Responsible Energy Development Act* ("*REDA"*) for a regulatory appeal of the AER's decision to approve certain licences of ConocoPhillips Canada Resources Corp. ("Conoco"). The AER decided that Mr. and Ms. Callan were not directly and adversely affected by the decision. The request for a regulatory appeal was therefore dismissed.

<u>Reasons for Decision</u>

The decision that was the subject matter of this appeal request was a Class II oilfield waste management facility approval issued pursuant to the *Oil and Gas Conservation Act* and *Rules*.

The Callans asserted their rights to harvest and carry out their aboriginal way of life in relation to a trapline. However, there was no information in the grounds for the regulatory appeal request that demonstrated how the Callans' trapping, harvesting and other activities may be affected by the approved oilfield waste landfill. No information was provided regarding any specific locations of trapping or other activities or assets that are on or near the proposed landfill. In the absence of such information, the Callans failed to demonstrate that they are or may be impacted by the approved landfill.

The Callans also asserted that they had a right to be consulted about the landfill; however, the AER has no jurisdiction with respect to assessing the adequacy of Crown consultation associated with the rights of aboriginal peoples. The AER noted that the Aboriginal Consultation Office issued its consultation adequacy decision, relating to the issuance of the Miscellaneous Lease under the *Public Lands Act* application for this project on March 13, 2018.

Regarding the Callans' concerns about a lack of information, the AER noted that Conoco complied with all AER notification and participant involvement requirements in respect of the approved landfill.

The AER noted that the Callans did not file a reply submission to challenge any of Conoco's responses.

<u>Conclusion</u>

The AER found that the Callans did not demonstrate that they are or may be directly and adversely affected by the AER's decision to approve the oilfield waste landfill, and were therefore not 'eligible persons' under the *REDA*. The request for regulatory appeal was dismissed.

Revised Date for Move of New Well Applications to OneStop, AER Bulletin 2019-24

Bulletin - Well Applications

On October 3, 2019, the AER issued *Bulletin 2019-22,* announcing that all applications for new well licences would need to be submitted through OneStop as of October 17, 2019. This move was delayed and will now occur on November 7, 2019.

The Digital Data Submission system will stop accepting new well applications as of 5:00 p.m. on October 31, 2019, as a result of this transition to OneStop. A OneStop outage will be scheduled to implement the requisite changes.

ALBERTA UTILITIES COMMISSION

ATCO Electric Ltd. 2018-2019 Transmission General Tariff Application, AUC Decision 22742-D02-2019

Rates - General Tariff Application - Retirement of Destroyed Assets

In this decision, the AUC considered utility asset disposition and other matters pertaining to the Fort McMurray wildfire, filed as part ATCO Electric Ltd. ("AET")'s 2018-2019 transmission general tariff application ("GTA"). The AUC found the undepreciated capital costs of assets destroyed in the Fort McMurray wildfire were for the account of customers.

Fort McMurray Wildfire Considerations

With respect to the Fort McMurray wildfire, AET provided the following summary of the event in its 2018-2019 GTA:

> In May of 2016, sustained strong winds fueled a series of wildfires in the vicinity of the community of Fort McMurray. Over the course of several days, fueled by strong winds, the fire grew to approximately 590,000 hectares. The fire spread through the city of Fort McMurray, impacted operations in the Athabasca Oil Sands, and threatened several transmission substations and powerline facilities in the area. During this period of time it destroyed thousands of homes within the city and is estimated to have cost $3.58 billion in insurable damages. Roughly 88,000 people were evacuated in the municipality of Wood Buffalo.

As a result of the wildfire, AET experienced what it described as "losses" to overhead transmission facilities, substations and telecommunication facilities. Consequently, AET developed the Fort McMurray Wildfire Transmission Asset Restoration Project (the "Project") for which it forecast $7.8 million for 2016 and 2017. The actual capital amounts incurred in connection with the Project in 2016 and 2017 were $7.0 million and $0.6 million, respectively.

AUC Findings

The entirety of the AUC panel determined that the unrecovered capital investment in the retired assets was for the account of the customers of AET, albeit for different reasons.

Findings of Acting Commission Member Romaniuk and Commission Member Sebalj

Commission Member Romaniuk and Commission Member Sebalj noted that in Decision 2013-417, the utility asset disposition ("UAD Decision"), the AUC made a distinction between asset retirement causes or events that had been considered in the determination of the depreciation parameters, which were referred to as "ordinary retirements," and those that had not been considered, which were referred to as "extraordinary retirements." The Commissioners explained that any unrecovered utility investment in an asset taken out of service as the result of an ordinary retirement would be for the account of customers because the type of retirement had been factored into the determination of the useful life of the applicable class of assets, the depreciation parameters and the resulting rates.

In contrast, Commission Member Romaniuk and Commission Member Sebalj explained that an asset taken out of service as the result of an extraordinary retirement would be for the account of the utility shareholders because the nature of that retirement had not been factored into the useful life of the applicable class of assets, the depreciation parameters and the resulting rates. What is important in determining whether a retirement event is ordinary or extraordinary, the Commissioners found, is whether it is reasonable to assume that the causes of the retirement event have been anticipated or contemplated in the determination of the depreciation parameters, not the impact that the retirement event may or may not have had on those parameters.

Commission Member Romaniuk and Commission Member Sebalj noted that, in Decision 24369-D01-2019, the AUC referred to earlier decisions, including the UAD Decision, and emphasized that each utility asset disposition situation is unique and must be evaluated on its individual facts.

Commission Member Romaniuk and Commission Member Sebalj determined, as a finding of fact, that the characteristics of the Fort McMurray wildfire retirement event were sufficiently similar in nature to the characteristics of retirement events that AET could be reasonably assumed to have been anticipated or contemplated in the preparation of its past depreciation study. As a result, the Fort McMurray wildfire retirement event was factored into the derivation of the existing depreciation parameters. Accordingly, the AUC found that the Fort McMurray wildfire gave rise to an ordinary retirement of the destroyed assets, for the account of customers.

Findings of Acting Commission Member Lyttle

Commission Member Lyttle found that the application of the UAD Decision will result in a nature-related event that might have been considered extraordinary in the past now being considered ordinary because the opportunity to have contemplated the event in a depreciation study has now occurred. Commission Member Lyttle noted that this exercise is likely to lead to inconsistent regulatory treatment over time of similar nature-related events in determining what constitutes ordinary and extraordinary retirements of utility assets. Commission Member Lyttle found that the ultimate logical outcome is that, eventually, all retirement events will be considered ordinary. Ultimately, as natural events are considered ordinary in all, or virtually all, circumstances, the UAD test for extraordinary retirement versus ordinary retirement will be moot.

Commission Member Lyttle found that to remove the undepreciated costs of the destroyed assets from rate base, one would need to find that the assets were no longer used and required to be used for the provision of utility service. The fire that devastated Fort McMurray did not destroy the need for the assets, nor the requirement for service.

Commission Member Lyttle explained that the capacity needed to operate the electric transmission facility in Fort McMurray is still required for utility service. In Commission Member Lyttle’s view, to assign the loss to the account of shareholders, the event would have had to also eliminate or alter the need to provide the service, not just destroy the individual components of the electricity delivery mechanism. The need for the utility to have the capacity to deliver the service in Fort McMurray continues. The utility service remains used or required to be used by the public. Therefore, Commission Member Lyttle found, the undepreciated capital costs of the destroyed assets continue to be associated with a service that is used or required to be used by the public and should continue to be recovered from customers.

<u>Future Considerations</u>

The AUC indicated it appreciates the difficulty utilities face operating in an environment where they must anticipate reasonably foreseeable future events, not just to properly align depreciation parameters but also to reduce the risk of shareholder losses due to an extraordinary retirement. The AUC noted that, notwithstanding these efforts, no party benefits if utilities are compelled to respond to negative economic incentives by adopting risk-averse policies that impede regulatory efficiencies or improvements in service or reliability where prudent investment would otherwise occur. These are perhaps some of the possible deleterious effects on the regulation of utilities in Alberta noted by the courts.

The AUC noted that UAD matters are complex and include not only the allocation of risk for ordinary and extraordinary retirements, but also involve the disposition of utility property, the withdrawal of utility property for non-regulated purposes, the underutilization of utility assets and the determination of a fair return on utility investment. Each aspect of these issues goes directly to the setting of just and reasonable rates in the context of the applicable law and the relevant circumstances.

The AUC indicated that it made these comments in the expectation that they will encourage debate on the evolution of public utility regulation in Alberta while the AUC continues to carry out its main function of fixing just and reasonable rates and in protecting the integrity and dependability of the supply system.

***ATCO Electric Ltd. Application for Disposal of 2015-2017 Transmission Deferral Accounts and Annual Filing for Adjustment Balances*, AUC Decision 24686-D01-2019**

Rates - Proceeding Participation - Advance Funding

In this decision, the AUC considered an application for advance funding by the Consumers’ Coalition of Alberta (“CCA)” (the “Advance Funding Application”) in connection with its participation in Proceeding 243751 (the “Original Proceeding”). The AUC approved advance funding for the CCA in the amount of $418,213.53.

<u>The Advance Funding Application</u>

The CCA submitted the Advance Funding Application on June 27, 2019, pursuant to Section 7 of Rule 022: *Rules on Intervener Costs in Utility Rate Proceedings*.

In support of its request for advance funding, the CCA submitted proposed cost budgets in the pre-GST amounts of $475,723.00 for the consulting services provided by Bema Enterprises Ltd. (“Bema”), and $93,275.00 for legal services provided by Mr. James Wachowich, Q.C. of Wachowich & Company. The CCA estimated its total consulting and legal costs, including GST, at $597,448 and requested advance funding in the amount of 70 percent of this estimate.

AUC’s Authority to Award Advance Funding

The AUC noted that its authority to award costs for participation in a utility rates proceeding is found in Section 21 of the *Alberta Utilities Commission Act*. In assessing an advance funding request, the AUC applies sections 3 and 7 of Rule 022, which state:

> **3. Costs Eligibility**
>
> 3.1 The Commission may award costs to an intervener who has, or represents a group of utility customers that have, a substantial interest in the subject matter of a hearing or other proceeding and who does not have the means to raise sufficient financial resources to enable the intervener to present its interest adequately in the hearing or other proceeding.
>
> …
>
> **7. Advance of fund request**
>
> 7.1 An eligible intervener in a hearing or other proceeding may, at any time before or during the hearing or other proceeding, make a request to the Commission for an advance of funds.
>
> 7.2 An application for advance funding must include a budget in accordance with Section 6 and include information substantiating the need for advance of funds.
>
> 7.3 If the Commission awards an advance of funds to an eligible intervener under this section, the Commission may issue an order directing the applicant to advance funds to the eligible intervener and set out the terms for repayment of the advance to the applicant by the eligible intervener if the Commission varies or denies costs on the claim for costs filed by the eligible intervener at the close of the hearing or other proceeding.

AUC Decision

The AUC determined that some advance funding was warranted in this case for the CCA to present its interests adequately in the Original Proceeding.

The AUC accepted the CCA’s assertion that it did not have the means to raise sufficient financial resources to enable it to adequately present its interests in the Original Proceeding without advance funding.

The AUC observed that, based on the current schedule for the Original Proceeding, the CCA does not expect the Original Proceeding to conclude for some time. Consequently, the time period between the incurrence of costs and the approval of final costs could be significant. Further, the AUC noted that the record of the Original Proceeding is voluminous, including 463 exhibits at the time that the advance funding application was filed, and includes confidential materials, which could lead to a significant use of consulting and legal resources.

The AUC noted that, historically, it has awarded between 30 and 60 percent of an intervener’s projected costs as advance funding where evidence supports an advance funding award. The AUC approved advance funding of 70 percent in Proceeding 22393. The AUC noted that similarly to Proceeding 22393, the dollar amounts involved in the original proceeding are significant, the record is large, and the length of time until the final cost award is made may be over one year from the date that costs are incurred.

The AUC found that an advance funding award of 70 percent of the budgeted costs, including GST, had been demonstrated and that such an award was consistent with the objectives of sections 3 and 7 of Rule 022. Accordingly, the AUC granted an advance funding award of 70 percent of the CCA’s budgeted costs, including GST consisting of $398,298.60 for the sum of the legal and consultant budgets before GST ($568,998.00 × 70 percent) and GST on this amount of $19,914.93 ($28,449.90 × 70 percent) for a total of $418,213.53.

The AUC noted that the advance funding approved in this decision would be subject to adjustment when a final costs decision is rendered following completion of the original proceeding.

ATCO Electric Ltd. - Z Factor Adjustment for the 2016 Regional Municipality of Wood Buffalo Wildfire, AUC Decision 21609-D01-2019

Rates - Performance Based Regulation - Z factor - Utility Asset Disposition

Decision Summary

In this decision, the AUC considered an application from ATCO Electric Ltd. ("ATCO Electric") to recover $15 million through a Z factor rate adjustment to compensate it for the costs it incurred as a result of the 2016 Regional Municipality of Wood Buffalo ("RMWB") wildfire and other northern Alberta wildfires. The AUC determined that:

- The RMWB wildfire, the Boundary Lake area wildfire and the Fox Creek wildfire were separate events for the purpose of determining Z factor eligibility;
- The Boundary Lake area and the Fox Creek wildfires were denied Z factor treatment;
- The 2016 costs claimed for the RMWB wildfire as an exogenous adjustment were prudently incurred, subject to the removal of certain operating and maintenance ("O&M") expenditures related to manager and supervisory labour costs and to information technology ("IT"), and subject to a correction to account for insurance proceeds received by ATCO Electric;
- The 2017 costs claimed for the RMWB wildfire as an exogenous adjustment were prudently incurred, subject to the removal of certain lost revenue costs;
- The RMWB wildfire gave rise to an extraordinary retirement of the destroyed assets;
- All replacement assets were used or required to be used in 2016 and 2017;
- Because the magnitude of the AUC directed adjustments required for 2016 was relatively small, the AUC found that ATCO Electric's Z factor for 2016 was material; and
- Because of the removal of certain costs directed by the AUC, a reassessment of whether the Z factor adjustment for 2017 is material and therefore meets Z factor Criterion 2 is required.

Introduction

In Decision 2012-237, the AUC established a performance based regulation ("PBR") plan for the Alberta electric and natural gas distribution companies for 2013-2017. The plan included a provision for a Z factor to allow for the recovery of certain specified costs outside of the I-X mechanism. Specifically, the AUC stated:

> A Z factor is ordinarily included in a PBR 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.

On May 13, 2016, ATCO Electric notified the AUC that it anticipated filing a Z factor application for the recovery of costs associated with the 2016 wildfires experienced in the RMWB and other northern Alberta areas (the Boundary Lake area and Fox Creek), collectively referred to as the wildfires.

On August 3, 2018, ATCO Electric filed an application with the AUC requesting approval to recover from its customers, O&M expenditures and the revenue requirement related to capital and revenue lost as a result of the wildfires. ATCO Electric applied for a total Z factor adjustment of $15 million.

Z factor criteria

In Decision 2012-237, the AUC established the following criteria to be applied when evaluating whether the impact of an exogenous event qualifies for Z factor treatment:

> (1) The impact must be attributable to some event outside management's control.
>
> (2) 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.

(3) The impact of the event should not have a significant influence on the inflation factor in the PBR formulas.

(4) All costs claimed as an exogenous adjustment must be prudently incurred.

(5) The impact of the event was unforeseen.

All of the above criteria must be met for an event to qualify for a Z factor rate adjustment.

The Event

In its application, ATCO Electric included capital costs incurred to rebuild assets destroyed by the RMWB wildfire (also referred to as the Fort McMurray fire), a wildfire in the Boundary Lake area (Fairview or also referred to as the Siphon Creek wildfire) and a wildfire in the Fox Creek area.

In ATCO Electric's view, the wildfires constituted one event for Z factor purposes, similar to the 2013 Southern Alberta flood event that affected numerous communities, for which ATCO Gas recovered its costs, as approved by the AUC in Decision 2738-D01-2016.

The Consumers' Coalition of Alberta and the Utilities Consumer Advocate opposed the aggregation of the wildfires into a single Z factor adjustment. They argued that the wildfires were three separate and distinct events: the RMWB wildfire, the Boundary Lake area wildfire and the Fox Creek wildfire.

AUC Findings

In Decision 2012-237, the AUC established Z, Y and K factors to recognize that certain prudently incurred costs may not be recoverable through the I-X mechanism. The AUC made the following determinations to recognize that not all events beyond the control of the company will qualify for a Z factor adjustment because adjustments of this nature have the effect of lessening the efficiency incentives that are central to a PBR plan:

> 534. Exogenous events may occur during the PBR term but by definition they are exceptional occurrences which may either add costs to, or remove costs from, the provision of utility service. Additionally, not all events beyond the control of the company will qualify under other Z factor criteria, thereby further reducing the number of already rare events that could result in a rate adjustment outside of the I-X mechanism. Given the exceptional nature of a qualifying exogenous event and the equally exceptional measure of authorizing a recovery outside of the I-X mechanism, the Commission considers that the PBR principles require a relatively high threshold and that this threshold should apply to each event unless otherwise permitted in exceptional circumstances. [Emphasis added]

Accordingly, a Z factor adjustment should only be permitted when it is determined that the impact of an event: (a) is outside of management's control; (b) has had a sufficiently significant impact on the operation of the company; and (c) that the costs of the event cannot be reasonably recovered through the revenues provided under the I-X mechanism.

The AUC found that unlike the 2013 Southern Alberta flood event, whereby Alberta experienced heavy rainfall, resulting in severe flooding along the Bow, Elbow, Red Deer and Highwood rivers, the Alberta wildfires were discrete fires.

Having determined that the Boundary Lake area and Fox Creek wildfires were discrete events, the AUC noted that these events must, therefore, meet the criteria for Z factor treatment on a stand-alone basis. Because ATCO Electric aggregated the capital costs of all wildfires in this application, the AUC could not make a determination regarding whether the costs associated with these fires are material and were prudently incurred. Consequently, the AUC denied Z factor treatment for the capital costs incurred as a result of the Boundary Lake area and Fox Creek wildfires. The AUC noted that this determination does not preclude ATCO Electric from submitting separate Z factor applications or a capital tracker (K factor) true-up application for additional funding for these capital costs.

Having regard to its findings on the Boundary Lake area and Fox Creek wildfires, the AUC only assessed the RMWB wildfire against the five Z factor criteria.

First and Fifth Criteria

The AUC recognized that the specific timing and location of the RMWB wildfire and its impact to the

Fort McMurray area was unforeseen and outside of management's control, thus satisfying the first and the fifth criteria for Z factor treatment.

Second Criterion

The AUC noted that ATCO Electric's applied-for Z factor adjustment of $10.4 million for costs incurred in 2016 significantly exceeds the approved 2016 materiality threshold of $2.330 million. The AUC was therefore satisfied that ATCO Electric's Z factor for 2016 was material.

The magnitude of the adjustments for 2017 as directed in this decision are more significant relative to the 2017 materiality threshold of $2.370 million. The AUC could not, therefore, determine in this decision whether ATCO Electric's Z factor for 2017 was material. The AUC directed ATCO Electric to reassess whether its Z factor for 2017 satisfies the materiality threshold requirement of Criterion 2 in its compliance filing.

Third Criterion

The AUC found that there was no evidence that the RMWB wildfire had a significant influence on the inflation factor in the PBR formula.

Fourth Criterion

As outlined below, the AUC determined that the O&M costs claimed for 2016 as an exogenous adjustment were prudent, with the exception of the supervisory and management labour costs, certain IT costs, and those costs subject to a correction due to insurance proceeds received by ATCO Electric.

Labour Costs

The AUC was satisfied that the O&M costs incurred in response to the RMWB wildfire in 2016 to enable service were reasonable, with the exception of the supervisory and management labour costs. The O&M costs were also subject to the adjustments and directions set out by the AUC in this decision.

Regarding the labour costs of supervisory and management employees seconded to the RMWB wildfire, the AUC found that there was insufficient evidence to support ATCO Electric's contention that all normal business activities of such supervisors and managers in their home locations were backfilled using overtime and contractors. The AUC noted that ATCO Electric management and supervisory staff are not paid overtime. The AUC, therefore, denied Z factor treatment for the supervisory and management labour costs for the RMWB wildfire.

Insurance Coverage

The AUC was satisfied with the level of detail provided by ATCO Electric with regard to insurance coverage and concluded that the updated insurance recovery amount is $0.085 million.

IT Costs

Consistent with the findings in Decision 20514-D02-2019, including that the IT services sourcing strategy was not prudent, the AUC found that the IT costs paid to Wipro as applied for in this application were not prudently incurred. The AUC directed ATCO Electric to adjust the $0.061 million paid to Wipro to reflect the AUC's disallowance and glide path reductions and to clearly show all calculations in the compliance filing to this decision.

Capital Expenditures

The AUC reviewed the capital costs, in general, that were incurred by ATCO Electric in response to the RMWB wildfire and found the scope of the work performed, the timing of the restorations and the quantum of the capital costs to be prudent. The AUC was persuaded by the evidence provided by ATCO Electric, indicating that basic variability of actual costs and the fact that the costs at issue were incurred under extreme working conditions resulted in higher costs as compared to historical actual results. The AUC was also of the view that the emergency conditions and ATCO Electric's obligation to provide electric utility service to the RMWB in a timely manner may have contributed to the higher costs.

Utility Asset Disposition Issues

This section discusses two issues relating to matters reviewed by the AUC in the utility asset disposition ("UAD Decision"), Decision 2013-417. In that decision, the AUC reviewed the symmetrical allocation of benefits and risks associated with property ownership by Alberta utilities based on the applicable legislation and the property and corporate law principles established by the courts, starting with the Stores Block decision. These issues arise from the retirement and replacement of assets as a result of the RMWB wildfire. First, the AUC reviews the treatment of unrecovered investment related to assets destroyed in the RMWB wildfire to determine whether the retirement of these assets constitutes an "ordinary retirement" with the consequence that any unrecovered investment is for the account of customers or an "extraordinary retirement" with the result that ATCO Electric's shareholder would bear any such under-recovery. Secondly, the AUC reviews the specific assets that were replaced to determine if any of these assets are not being used to provide utility service and should be removed from rate base.

Regulatory Treatment of Assets Destroyed in the RMWB Wildfire

The AUC noted that an asset taken out of service as the result of an extraordinary retirement would be for the account of the utility shareholders because the nature of that retirement had not been factored into the determination of the depreciation parameters. What is important in determining whether a retirement event is ordinary or extraordinary, is whether it is reasonable to assume that the causes of the retirement event have been anticipated or contemplated in the determination of the depreciation parameters, not the impact that the retirement event may or may not have had on those parameters.

ATCO Electric's last AUC approved depreciation study before was filed in its 2011-2012 GTA. The study analyzed historical data up to December 31, 2008. In assessing the characteristics of the retirements resulting from the RMWB fire, the AUC made a finding of fact that the characteristics of this retirement event were very similar to the characteristics associated with the Slave Lake retirements and decision [Decision 2014-297 (Errata)]. In the latter decision, the AUC found: (a) the retirements resulted from causes that "could not reasonably have been anticipated or contemplated in the determination of the parameters used in the previous depreciation study dated as at December 31, 2008"; and (b) that "for regulatory purposes the Slave Lake fires give rise to an extraordinary retirement of the destroyed assets."

In this proceeding, the evidence confirmed that the RMWB fire was "one of the largest natural disasters Canada has ever faced" devastating the community and its electric distribution utility infrastructure. Further, in the Slave Lake decision, the AUC reviewed the evidence, including the history of nature-related events causing retirements experienced by ATCO Electric over a 10-year period. The AUC determined that the nature of these past retirement events, which generally involved replacement costs in the range of $1 million to $2 million, were sufficiently different from the Slave Lake region fire. The Slave Lake region fire required replacement costs of assets of $23.7 million. Similarly, in this proceeding, the AUC considered the information provided by ATCO Electric on the history of retirements on similar assets due to nature-related events that occurred prior to the completion of the previous depreciation study approved by the AUC. The AUC observed that the repair/replacement costs due to nature-related events prior to 2009 range from $0.0 million to $0.6 million. The replacement costs associated with the RMWB wildfire totalled $28.8 million, a characteristic that is comparable to the replacement costs associated with the Slave Lake region fire.

As noted above, the AUC considers if the characteristics of a particular retirement event are sufficiently different from the characteristics of previous events causing retirements. If they are, then it cannot be reasonably assumed that the particular retirement event resulted from causes anticipated or contemplated in a previous depreciation study and factored into the derivation of the existing depreciation parameters.

The AUC made a finding of fact that a retirement event with similar characteristics to the retirements caused by the RMWB wildfire could not reasonably have been anticipated or contemplated in the determination of the parameters used in the previous depreciation study.

Accordingly, for regulatory purposes, the RMWB wildfire gave 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 was directed, in the compliance filing to this decision, to provide all accounting entries reflecting the retirement of the assets destroyed by the RMWB wildfire.

Future Considerations

The AUC noted that although the Court of Appeal emphasized that the *Stores Block* line of cases remains good law, the Court also noted that more than a decade of incremental litigation on individual, fact-specific AUC decisions has arguably resulted in some “deleterious effects on regulation of utilities in Alberta.” In making this observation, the Court indicated that the AUC would have greater flexibility to deal with utility asset disposition (“UAD”) matters in the absence of this line of Court decisions. The AUC noted that the Court reminded lawmakers that they have the ability to consider these issues from a broader public policy perspective should they wish to alter the status quo and provide the AUC with greater discretion in addressing UAD fact-specific issues.

Regarding the possible deleterious effects on the regulation of utilities, the AUC noted that it appreciates the difficulty utilities face operating in an environment where they must anticipate reasonably foreseeable future events not just to properly align depreciation parameters, but also to reduce the risk of shareholder losses due to an extraordinary retirement. Notwithstanding these efforts, utilities recognize that shareholder losses are likely to occur despite having acted prudently in conducting their operations. Similarly, it is not in the interest of customers that they pay higher rates that reflect risk-adjusted returns or depreciation parameters and investment decisions which factor in every possible retirement contingency. It is also not in the interest of customers that utilities incur higher borrowing costs or that the delivery of safe and reliable service be compromised due to financial hardship resulting from an extraordinary retirement. Further, it is in the interest of neither utilities nor customers to engage in continual fractious debate in characterizing retirements. Again, no party benefits if utilities are compelled to respond to negative economic incentives by adopting risk-averse policies that impede regulatory efficiencies or improvements in service or reliability where prudent investment would otherwise occur.

The AUC noted that UAD matters are complex and include not only the allocation of risk for ordinary and extraordinary retirements, but also involve the disposition of utility property, the withdrawal of utility property for non-regulated purposes, the underutilization of utility assets and the determination of a fair return on utility investment. Each aspect of these issues goes directly to the setting of just and reasonable rates in the context of the applicable law and the relevant circumstances.

The AUC concluded this discussion by noting that it makes the above comments in the expectation that they will encourage debate on the evolution of public utility regulation in Alberta while the AUC continues to: (a) carry out its main function of fixing just and reasonable rates (‘rate setting’); and (b) in protecting the integrity and dependability of the supply system, as directed by the legislation and as interpreted and applied by the courts.

Regulatory Treatment of Replacement Assets

ATCO Electric added $26.0 million in capital additions to its rate base as a result of the wildfires that destroyed overhead and underground distribution facilities in several neighbourhoods in the RMWB and in the Boundary Lake and Fox Creek areas. The AUC examined the status of the services, active or inactive, in each neighbourhood in RMWB and considered whether the assets providing utility service are used or required to be used, as contemplated by the AUC in the UAD Decision.

The maps provided by ATCO Electric showed the status of the services affected by the RMWB wildfire. By August 31, 2018, most services were active and, therefore, most assets were being used to provide electric utility service. The AUC noted two neighbourhoods, Abasand and Beacon Hill/Waterways, where the maps showed destroyed properties and inactive sites not interspersed with active sites, indicating that potentially no utility service was being provided in these areas.

The AUC was satisfied that utility service is being provided in the Abasand areas. The AUC accepted ATCO Electric’s explanation that facilities were required in order to restore streetlights for public safety and to supply service to sites in the reasonably foreseeable future. Regarding the areas of interest in the Waterways area, the AUC was satisfied that for 2016 and 2017, ATCO Electric was required to ensure facilities were in place to provide utility service to customers when they returned to the area in order to meet its obligation to supply service as required by the municipality. However, the AUC found that in the case of the Waterways area, it is unclear whether all assets in this area are used or required to be used to provide electrical service after 2017.

Accordingly, the AUC found that, for 2016 and 2017, the replacement assets were presently used, reasonably used, and likely to be used in the future to provide service. However, the AUC did not have sufficient evidence to determine whether certain lines require abandonment because customers have not returned to certain areas or customers will not be permitted to build in the area served by those lines. Therefore, the AUC is not making any determination as to whether all the replacement assets were used or required to be used after 2017.

The AUC required that ATCO Electric file further information in its compliance filing to allow the AUC to determine whether all of the repaired and replaced assets will continue to be used or required to be used after 2017.

Lost Revenue

ATCO Electric also applied to recover $3.075 million of waived charges in 2016, $2.597 million of lost revenue for 2016 and $2.101 million of lost revenue for 2017.

The AUC found that the waived charges and revenue lost for 2016 as a result of the RMWB wildfire are eligible for inclusion in the Z factor adjustment and, therefore, recoverable. However, given the ability of ATCO Electric to disconnect a service after 12 months where it is not receiving any revenue from that service, the AUC denies Z factor treatment for the lost revenue for sites that remained inactive after May 2, 2017, 12 months after the start of the mandatory evacuation period.

AUC Conclusions on the Z Factor Adjustment

The AUC noted that since the filing of the current application, in Decision 23895-D01-2018, the AUC approved a 90 percent Z factor placeholder to be included in ATCO Electric's 2019 PBR rates, subject to true-up in subsequent PBR annual filings to reflect the approved amount.

Given the above, the AUC directs ATCO Electric, in the compliance filing to this decision, to remove any costs associated with the Boundary Lake area and Fox Creek wildfires, recalculate the revenue requirement for 2016 and 2017 identify and remove the manager and supervisory labour costs from the O&M expenditures, adjust the insurance proceeds amount, adjust the IT service costs to reflect the directions in Decision 20514-D02-2019, recalculate the lost revenue for 2017 by excluding inactive sites after May 2, 2017, and recalculate the total Z factor amount for 2016 and 2017 to reflect these adjustments.

Order

The AUC ordered that ATCO Electric file a compliance filing application in accordance with the directions within this decision on or before November 13, 2019.

ATCO Gas and Pipelines Ltd. 2019 Unaccounted-For Gas Rider D, AUC Decision 24815-D01-2019

Rates - Unaccounted-for Gas Rider D

In this decision, the AUC considered an application from ATCO Gas (a division of ATCO Gas and Pipelines Ltd.) requesting approval of its unaccounted-for gas ("UFG") Rider D rate of 0.864 percent for 2019-2020, to be in effect from November 1, 2019. The AUC approved the UFG Rider D rate of 0.864 percent.

Background

Charges for UFG are recovered in-kind from all shippers on the ATCO Gas distribution system, including the default supply providers by way of Rider D. For example, if the AUC approved ATCO Gas's proposed Rider D rate of 0.864 percent, all customers of retailer and default supply providers utilizing distribution access service for delivering gas off the ATCO Gas distribution system would be assessed a distribution UFG charge of 0.864 percent at the point of delivery. The effect would be that all retailer and default supply provider customers must buy an extra 0.864 percent of natural gas in order to zero-balance their receipts and deliveries on the ATCO Gas system.

In its application, ATCO Gas explained that consistent with previous Rider D applications, it calculated its Rider D rate using measurement data from the preceding three years, in this case, from January 2016 to December 2018. ATCO Gas then averaged the UFG percentages for 2016, 2017 and 2018 to determine the Rider D rate for 2019.

AUC Findings

The AUC found that ATCO Gas's calculation of Rider D was consistent with the methodology approved in previous decisions, and in particular with Decision 23838-D01-2018. The AUC, therefore, approved Rider D at 0.864 percent, effective November 1, 2019.

In approving ATCO Gas's application, the AUC indicated it took into account the fact that the applied-for Rider D of 0.864 percent was below the historical range of the combined UFG rate (0.954 to 1.220 percent).

The AUC noted that it issued several directions to ATCO Gas in respect of the Rider D rate in previous decisions. Recently, in Decision 23838-D01-2018 it directed ATCO Gas as follows:

> 45. Accordingly and consistent with Decision 22889-D01-2017, the Commission directs ATCO Gas to continue to provide the following in future Rider D applications on an annual basis:
>
> - Clear explanations of seasonal UFG differences, measurement corrections and reasons for UFG increases or decreases; and
> - Information on practices and procedures it has employed to reduce UFG.
>
> 46. The Commission also directs ATCO Gas to continue to provide details with respect to all measurement adjustments showing the reconciliation of prior years' data in accordance with the direction found at page 7 of Decision 2008-105.

The AUC found that ATCO Gas complied with the directions of the AUC in Decision 23838-D01-2018. Specifically, in its application, ATCO Gas satisfactorily explained various measurement adjustments, the seasonal differences in UFG, the reason for changes in UFG, its efforts to implement operational changes and metering related to UFG, and provided a table showing the monthly line heater fuel usage, the associated carbon levy dollars and the difference from the previous year.

Aura Power Renewables Ltd. Empress Solar Power Plant, AUC Decision 23580-D01-2019

Facilities - Solar Power Plant

In this decision, the AUC considered whether to approve applications (the "Applications") from Aura Power Renewables Ltd. ("Aura") to construct and operate a solar power plant and to interconnect the power plant to FortisAlberta Inc.'s electric distribution system (the "Project"). The AUC found that approval of the Project was in the public interest having regard to the social, economic, and other effects of the Project, including its effect on the environment.

The Applications

Aura filed the Applications with the AUC for approval to construct and operate a 39-megawatt ("MW") solar power plant integrated with lithium-ion battery cell modules, in the County of Cypress, and to connect the power plant to FortisAlberta Inc.'s 25-kilovolt electric distribution system (the "Project").

Legislative Framework

The AUC indicated it considered the Applications under sections 11 and 18 of the *Hydro and Electric Energy Act,* which make it clear that no person can construct or operate a power plant, or connect a power plant to the interconnected Alberta system without the AUC's approval.

The AUC also noted that, in accordance with Section 17 of the *Alberta Utilities Commission Act*, the AUC must assess whether the Project is in the public interest, having regard to its social, economic and other effects, including its effects on the environment.

AUC Findings

The AUC determined that the technical, siting and noise aspects of the power plant had been met. Aura's participant involvement program had been conducted in accordance with Rule 007. Additionally, the AUC did not receive any objections from potentially impacted parties in the area. Therefore, the AUC found that it had no reason to believe there were outstanding public or industry objections or concerns.

The AUC noted that, currently, there are no standards or regulations in place related to public safety associated with solar glare. However, the AUC accepted the conclusion of Aura's solar glare analysis report that solar glare from the panels would not result in lasting health impacts on individuals, although an observer's vision could be temporarily affected by an after-image from solar glare.

Regarding the environmental effects of the Project, the AUC was satisfied that the Project's potential effects on the environment would be adequately mitigated. This conclusion was based on the expectation of diligent implementation of Aura's various commitments as well as adherence to conditions of approval set out by the AUC regarding updated kangaroo rat den surveys, a finalized kangaroo rat mitigation plan and an annual post-construction monitoring survey report.

The AUC noted that there are no existing market rules or regulations governing the operation of battery storage systems in Alberta. The AUC found that, notwithstanding the lack of legislation or rules specific to the incorporation of battery storage into a power plant, the *Electric Utilities Act* and the *Hydro and Electric Energy Act* provide direction to the AUC on their respective purposes. Both acts promote the economic, orderly and efficient development and operation of generating units in Alberta. In the AUC's view, no party, including Aura, filed any evidence on the record to suggest that approving the power plant with a battery storage component would be inconsistent with the stated purposes of the *Hydro and Electric Energy Act* or the *Electric Utilities Act*.

The AUC indicated it had concerns regarding potential environmental issues related to the replacement and recycling of degraded battery cells. The AUC considered that the improper disposal of battery cells could result in significant adverse environmental effects. Consequently, the AUC indicated it would impose as a condition of approval that Aura file a letter with the AUC no later than three months before the construction of the Project is to commence. The AUC indicated that the letter must identify specific details regarding the battery storage units and the battery supplier Aura has chosen, including whether Aura selected a battery storage supplier that has a recycling or disposal program.

Subject to the AUC's conditions of approval, the AUC considered the Project to be in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Ac*t.

***Blazer Water Systems 2019-2020 General Rate Application Compliance Filing*, AUC Decision 24418-D01-2019**

Rates - Water Utility - Compliance Filing

In this decision, the AUC considered a compliance filing from Blazer Water Systems Ltd. (Blazer") addressing all of the determinations and directions of the AUC in Decision 22319-D01-2018. In AUC Decision 22319-D01-2018, the AUC considered Blazer's 2019 to 2020 general rate application ("GRA"). The AUC found Blazer complied with its directions, as set out below.

<u>AUC Directions</u>

Bearspaw Village Water Co-Operative and Blueridge Rise Reserve Funds (Direction 1)

In paragraph 70 of Decision 22319-D01-2018, the AUC directed Blazer to provide the calculation of its $30 per month contingency fund amount for Bearspaw Village Water Co-Operative ("BPV") and Blueridge Rise ("BRR") and provide an explanation of why this amount should be approved. The AUC accepted Blazer's submission that it was administering the two reserve funds on behalf of BPV and BRR without additional cost to customers and that the $30 per month reserve fund was reasonable for maintenance of the BPV and BRR systems.

Opening Rate Base (Direction 6)

In paragraph 133 of Decision 22319-D01-2018, the AUC directed Blazer to update Schedule 12 of its financial model to reflect the actual net book value ("NBV") as of December 31, 2018. The AUC confirmed that Blazer had included an updated Schedule 12 in its financial model to reflect the actual NBV as of December 31, 2018.

Gifted Capital for Connection of BPV Water System (Direction 7)

In paragraph 135 of Decision 22319-D01-2018, the AUC directed Blazer to make corrections to certain data in Schedule 11 and Schedule 13 of its financial model, to properly account for $0.264 million that was gifted capital for the connection of the BPV water system to Blazer's system. The AUC confirmed that the $0.264 million had been removed from Blazer's invested capital in Schedule 11 and that the amount was properly included as gifted capital in Schedule 13.

Updated Actual and Forecast Capital Additions for River Intake Replacement (Direction 8)

In paragraph 148 of Decision 22319-D01-2018, the AUC directed Blazer to update its actual costs to date and forecast costs related to its capital additions for its river intake replacement project. The AUC found that Blazer's proposal to amend its capital plan to delay the originally proposed river intake improvements was reasonable.

Forecast Capital Additions – Contingency Allowance (Directions 9-10)

In paragraphs 151 and 152 of Decision 22319-D01-2018, the AUC directed Blazer to exclude any capital amounts for contingency allowance against unexpected works. The AUC confirmed that Blazer had removed these amounts.

Depreciation Expense of $0.150 Million Investment in BPV and BRR System Connections (Directions 15-16)

In paragraphs 172 and 173 of Decision 22319-D01-2018, the AUC directed Blazer to include a separate asset of $0.150 million for its investment in the BPV/BRR connection to the Blazer water system. The AUC further directed Blazer to calculate the opening NBV of this asset as of January 1, 2019. The AUC also directed Blazer to calculate the depreciation expense associated with the $0.150 million for 2019 and 2020. The AUC accepted Blazer's reasoning for allocating the $0.150 million proportionally across eight assets associated with the water treatment plant expansion. The AUC confirmed that Blazer correctly updated the opening NBV of the assets and that the depreciation for the $0.150 million was calculated as 3.93 percent of the depreciation expense for the water treatment plant expansion assets.

Depreciation (Directions 11-14 and 18)

In paragraph 163 of Decision 22319-D01-2018, the AUC directed Blazer to use the half-year rule for capital additions in 2019 and 2020. In paragraph 165, the AUC directed Blazer to adopt the straight-line basis of calculating depreciation. In paragraph 166, the AUC directed Blazer to calculate the deprecation for its capital assets as of December 31, 2018, based on the remaining expected life, their NBV as of December 31, 2018, and the depreciation rates approved in Table 8 of Decision 22319-D01-2018. In paragraph 167, the AUC directed Blazer to calculate the depreciation for any capital additions using the Table 8 depreciation rates and the half-year rule. The AUC confirmed that Blazer had correctly implemented the half-year rule and straight-line depreciation for its capital additions, and calculated the depreciation expense based on the remaining life of its assets and the depreciation rates approved in Table 8 of Decision 22319-D01-2018.

Cost of Debt, Return on Equity and Deemed Debt Equity Ratio (Direction 19)

In paragraph 188 of Decision 22319-D01-2018, the AUC directed Blazer to calculate, and show separately, return on debt with an interest rate of 4.0 percent, return on equity of 8.50 percent, a deemed equity ratio of 40 percent and a deemed debt ratio of 60 percent, for each of 2019 and 2020. The AUC confirmed that Blazer had included in Schedule 1.3 of its financial model the return on equity, the return on debt interest rate, and debt and equity ratios.

Blazer Subsidy (Direction 20)

In paragraph 203 of Decision 22319-D01-2018, the AUC directed Blazer to update its subsidy amount based on foregoing a percentage of its depreciation and return, whereby that percentage is calculated by dividing the forecast number of homes for the year by 1,250. The AUC concluded that Blazer had updated its subsidy amount by calculating the subsidy based on the number of forecast homes divided by 1,250.

Allocation of Depreciation on Capital Additions to BPV and BRR Connection (Direction 17)

In paragraph 174 of Decision 22319-D01-2018, the AUC directed Blazer to allocate any capital additions made subsequent to the water treatment plant expansion assets on the basis of water consumption. Blazer stated that there had been no capital additions to these assets since their addition to rate base, and no additions are forecast during the test period. The AUC confirmed that Blazer had not made any capital additions to these assets based on the information filed on the record.

Operating Costs (Directions 3-4, 25-26)

In paragraph 92 of Decision 22319-D01-2018, the AUC directed Blazer to reduce to 80 percent the amount of the general manager's salary allocated to Blazer's revenue requirement. The AUC confirmed that Blazer included 80 percent of the general manager's salary in its revenue requirement for the purposes of this compliance filing.

In paragraph 115 of Decision 22319-D01-2018, the AUC directed Blazer to explain the difference between the two different cost codes on the H2o Pro invoices, why the charges are split on the invoices, how the two amounts appearing on the invoices were derived and any potential consequences of not splitting the amounts. Blazer stated that its internal accounting reports split out the H2o Pro invoice charges into three separate amounts to maintain tracking of incremental increases in the monthly contract rate and that the amounts correspond to the rate prior to July 31, 2016, from August 2016 to August 2017, and after August 2017. The AUC accepted Blazer's explanation.

In paragraph 232 of Decision 22319-D01-2018, the AUC directed Blazer to exclude any advertising expenditures from the advertising and promotion cost category, which Blazer described as "consumer relations." The AUC also directed Blazer to provide a breakdown of the non-advertising expenditures, such as website maintenance, that will remain in the cost category. The AUC accepted Blazer's explanation of what costs are included in this cost category and that no advertising expenses are included. The AUC found that Blazer's proposed labelling of this cost category as "consumer relations" was reasonable because it reflected the costs included in this line item.

In paragraph 235 of Decision 22319-D01-2018, the AUC directed Blazer to establish separate general ledger accounts for bank charges and collection fees and to record the actual expenditures in the applicable account, starting in January 2019. The AUC acknowledged that because of the absence of collection charges and the renaming of the specific account to bank service charges, it was not necessary for Blazer to establish separate general ledger accounts for bank charges and collection fees.

Allocation of Operating Costs (Directions 5 and 23)

In paragraph 123 of Decision 22319-D01-2018, the AUC directed Blazer to change the customer base allocator to volume based and remove the time-of-use allocator from its operating and maintenance ("O&M") cost schedules. The AUC accepted Blazer's explanation that these costs increase as a function of the number of customers and acknowledged that treating Lynx Ridge as a single irrigation customer leads to a more reasonable allocation of costs between irrigation customers. The AUC accepted Blazer's explanation as to why general and administrative costs allocation based on volumes would not be reasonable.

In paragraph 222 of Decision 22319-D01-2018, the AUC directed Blazer to allocate the materials supplies and maintenance at the raw water pump station and electricity – river pump house cost categories based on water consumption. The AUC confirmed these two cost categories are now allocated based on water consumption.

Certain O&M Costs Allocated to BPV and BRR (Direction 24)

In paragraph 231 of Decision 22319-D01-2018, the AUC directed Blazer to remove any costs that relate specifically to the BPV and BRR water systems for three O&M cost categories from its revenue requirement: (i) materials and maintenance for the distribution system; (ii) materials and maintenance of hydrants; and (iii) warranty expenses. The AUC acknowledged Blazer's statement that the reserve funds had not been used to cover any costs that are included in its revenue requirement.

Capital Costs Allocators (Direction 27)

In paragraph 241 of Decision 22319-D01-2018, the AUC directed Blazer to replace its time-of-use allocator for capital costs with the consumption allocator. The AUC confirmed Blazer removed the time-of-use allocator for its capital costs and replaced it with an allocator based on water consumption.

Rate Design (Direction 28)

In paragraph 252 of Decision 22319-D01-2018, the AUC directed Blazer to design its potable water rates using average water consumption data specific to its two potable water rate classes and directed Blazer to update the average water consumption data using actuals for 2016. The AUC concluded that the allocation based on rate class specific average water consumption, updated for 2016 actuals, was now reflected in schedules 2.5, 3.3, 3.4 and 4D.

Terms and Conditions of Service (Directions 2, 21-22, 31-33)

In paragraphs 76, 288 and 290 of Decision 22319-D01-2018, the AUC directed Blazer to file consolidated terms and conditions of service. The AUC acknowledged that Blazer submitted consolidated terms and conditions.

In paragraph 204 of Decision 22319-D01-2018, the AUC directed Blazer to add a clause to its terms and conditions to include a capital costs recovery fee, called a "connection fee." In paragraph 205, the AUC directed Blazer to indicate whether it intends to charge the connection fee to new customers who are not part of new developments but rather existing homes, and to include a proposal for how existing homes will be addressed. The AUC confirmed that the tie-in-fee had been included in the terms and conditions of service.

In paragraph 294 of Decision 22319-D01-2018, the AUC directed Blazer to make changes to its terms and conditions necessary to reflect the change of the Lynx Ridge Estates community to a single irrigation customer. The AUC confirmed that the required change had been made.

Other Directions (Directions 29-30)

In paragraph 277 of Decision 22319-D01-2018, the AUC directed Blazer to notify the AUC of any amendment to the Lynx Ridge Golf Course agreement or rates in its next GRA. Blazer confirmed that it would notify the AUC of any such changes.

In paragraph 283 of Decision 22319-D01-2018, the AUC directed Blazer to confirm that it had implemented a one-time credit or charge to customers to dispose of an existing deferral account balance related to a complaint. The AUC confirmed that the one-time credit or charge had been implemented.

***EPCOR Distribution & Transmission Inc. 2020 Interim Transmission Facility Owner Tariff*, AUC Decision 24931-D01-2019**

Rates

In this decision, the AUC considered EPCOR Distribution & Transmission Inc.'s ("EPCOR's") request for a 2020 interim transmission facility owner ("TFO") tariff. The AUC approved EPCOR's application.

On September 25, 2019, EPCOR filed its application with the AUC pursuant to sections 37, 119 and 124(2) of the *Electric Utilities Act* requesting approval of an interim and refundable (TFO) tariff effective January 1, 2020.

<u>AUC Findings</u>

In Decision 24058-D01-2018, the AUC approved a TFO tariff revenue requirement in the amount of $99,191,603 for 2018 and $102,651,793 for 2019. The 2019 approved TFO tariff revenue requirement represented a monthly charge to the Alberta Electric System Operator ("AESO") of $8,554,316, effective January 1, 2019, to December 31, 2019.

On July 31, 2019, EPCOR filed its 2020-2022 TFO tariff application with the AUC, requesting approval of a forecast TFO tariff revenue requirement in the amount of $109,877,794 for 2020. For this interim rate application, EPCOR requested that its approved 2019 TFO tariff continue on an interim refundable basis at a monthly rate of $8,554,316. The AUC found that EPCOR's request to continue with the approved 2019 TFO tariff on an interim refundable basis is reasonable because:

- A final 2020 TFO tariff will not be approved and in place before January 1, 2020;
- There was no opposition to the application or evidence of prejudice to customers; and
- The interim rate promotes regulatory efficiency and short-term rate stability.

Accordingly, the AUC approved a 2020 interim refundable TFO tariff of $8,554,316 per month, effective January 1, 2020. The 2020 interim refundable TFO tariff approval shall remain in effect until replaced by a revised interim or final tariff.

***FortisAlberta Inc. Compliance Filing to Decision 21785-D01-2018,* AUC Decision 23961-D01-2019**

Compliance Filing - Electrical Distribution System Purchase - Depreciation Component

In this decision, the AUC considered whether to approve the depreciation component associated with FortisAlberta Inc. ("Fortis")'s purchase of the electric distribution system from the Municipality of Crowsnest Pass ("Crowsnest Pass" or the "Municipality"). The AUC found the depreciation amount of $2,936,000 to be reasonable.

<u>Background</u>

In Proceeding 21785, Fortis requested that the AUC assess the prudence of the price it paid to purchase Crowsnest Pass's electric distribution system, for ratemaking purposes. The AUC did not find the applied-for depreciation amount to be prudent. The AUC was not convinced that the applied-for depreciation component of $1,640,277 produced a value that was commensurate with the value of Crowsnest Pass's system. The AUC indicated that Fortis could reapply for approval of a revised purchase price in a compliance filing to that decision. Fortis applied for a revised depreciation amount in this proceeding.

Fortis's revised methodology resulted in an updated depreciation amount of $2,947,000 as compared to the previous depreciation amount of $1,640,277 based on the application of a 30.33 percent depreciation rate.

In the second round of information requests for this proceeding, the AUC requested that Fortis provide the depreciation component of the transaction based on the estimated service life and Iowa curve approved for each asset class. In response, Fortis provided a revised depreciation component value of $2,936,000.

<u>AUC Findings</u>

The AUC was generally satisfied that Fortis had provided a comprehensive depreciation methodology that better reflected the condition, vintage and necessity of the infrastructure assets acquired from Crowsnest Pass, as contemplated by the AUC in Decision 21785-D01-2018.

However, the AUC did not find certain aspects of the overall revised approach undertaken by Fortis, and the resultant depreciation amount of $2,947,000, to be an accurate representation of Crowsnest Pass's electric distribution system assets. Specifically, the AUC was not persuaded that utilizing the weighted average service life was superior to using estimated service lives specific to each asset class. The AUC found that Fortis's methodology of applying the weighted average service life of 42 years against the transformers and poles asset classes unnecessarily skewed the estimated service life of those assets.

The AUC also did not find Fortis's "blanket" approach of applying an R1.5 curve to each asset class to be reasonable in this instance. In the AUC's view, Fortis's proposed "blanket" approach unreasonably diminished a more precise way of determining depreciation amounts.

However, the AUC found the depreciation amount of $2,936,000, as calculated by Fortis in response to the AUC's second round of information requests resolved the AUC's concerns. Therefore, the AUC found the purchase price associated with the acquisition of Crowsnest Pass's electric distribution system in the amount of $2,450,180 (reflective of the replacement cost new value of $5,407,786, less the approved depreciation amount of $2,936,000, subject to adjustments for the acquisition of inventory in the amount of $99,480 and removal costs of $121,086) to be prudent for ratemaking purposes.

FortisAlberta Inc. - Capital Tracker True-Up for the 2016 and 2017 AESO Contributions Program, AUC Decision 24281-D01-2019

Rates

In this decision, the AUC considered FortisAlberta Inc.'s ("Fortis") 2016 and 2017 capital tracker true-up for its Alberta Electric System Operator ("AESO") Contributions Program. The AUC determined that:

- Fortis must review its pro forma Electric Service Agreement and other provisions to ensure that end-use customers are provided with sufficient incentives to request only the capacity that they reasonably expect to require and that sufficient safeguards are in place to guard against forecast risk.

- The Consumers' Coalition of Alberta's ("CCA") request for a refund of 50 percent of the amount calculated by Fortis in relation to the cost of complying a direction from Decision 22741-D01-20181 represented a collateral attack and was denied.

- Adjustments are required for projects with costs transferred from cancelled projects.

- The application of the allowances for funds used during construction ("AFUDC") true-up in respect of 2016 rather than 2017 has the effect of allowing the AFUDC to be reflected in the K-bar calculation for the 2013-2016 period, and is consistent with the AUC's finding which applies risk-reward mechanism disallowances to 2016 rather than in 2017.

- Fortis is directed to apply risk-reward reductions totalling negative $1,222,085, as an adjustment to its 2016 AESO contribution amount.

- Given the approval of the AESO's grandfathering proposal in Decision 22942-D02-2019, the AUC's adoption of the AESO's adjusted metering practice in that decision will not require any adjustments to AESO contribution amounts for the years 2016 and 2017 within this decision.

- Fortis must identify all projects it listed where the cumulative AESO contribution addition amounts for 2016 or 2017 are based on estimated values.

- A reassessment of whether the AESO Contributions Program included in Fortis's 2016 and 2017 true-up satisfies the project assessment and accounting test requirements of Criterion 1 is required.

The AUC directed Fortis to recalculate its accounting test requirement of Criterion 1 for 2016 and 2017 in a compliance filing reflecting the findings in this decision.

The AUC also noted that findings in this decision are limited to the true-up of Fortis's AESO contribution amounts for 2016 and 2017. The AUC recognized that the subsequent treatment of the unamortized balances of Fortis's AESO contribution amounts, including those that are the subject of this decision, was addressed in Decision 22942-D02-2019. Decision 22942-D02-2019 is subject to a review and variance ("R&V") application filed by Fortis; this application is currently being addressed in Proceeding 24932 (the "R&V Proceeding"). By approving certain AESO contribution amounts in this decision, the AUC noted that it was not commenting on the appropriate subsequent treatment of these amounts.

<u>Background</u>

On February 6, 2017, the AUC issued Decision 20414-D01-2016 (Errata), which set out the parameters of the 2018-2022 Performance Based Regulation ("Next Generation PBR") plan for AUC-regulated distribution utilities, including Fortis. In that decision, the AUC also established a rebasing methodology to transition from the 2013-2017 PBR plan to the 2018-2022 PBR plan. The Next Generation PBR plan and the rebasing methodology adopted require a determination of the final approved capital expenditure amounts for the years prior to 2018. Therefore, the final amounts for Fortis's 2013-2017 capital tracker programs, including its AESO Contributions Program, must be determined.

<u>Summary of AESO Contributions Program Included in the 2016 and 2017 Capital Tracker True-up Application</u>

Fortis applied for finalization of its 2016 and 2017 capital tracker true-up amounts for its AESO Contributions Program. In the application, Fortis explained that the 2016 K factor revenue true-up refund associated with the AESO Contributions Program was reduced by $0.5 million as a result of including the net capital additions related to the Cochrane and Okotoks/High River project legacy costs in the 2016 closing rate base.

<u>Project Assessment Under Criterion 1</u>

The AESO Contributions Program recognizes the cost to Fortis of contributions paid to the AESO for the construction of transmission facilities that have been approved by the AUC.

Fortis's AESO Contributions Program included in the 2016 and 2017 true-up was evaluated against the second part of the project assessment requirement of Criterion 1: whether the actual scope, level, timing and costs of the project are prudent.

Projects Involving a Material Variance Between the Actual Load and the Forecast Load and the Effect of Such Discrepancies on AESO Contribution Prudence

The AUC noted that in "need for development" or "NFD" reports prepared by Fortis in support of the transmission connection projects, Fortis typically prepares a breakdown of historical load for each feeder at a substation, as well as a forecast of the load that Fortis expects at both existing substation feeders and any proposed new substation feeders.

The AUC asked Fortis questions about 23 projects that appeared to show a material variance between the actual load and the forecast load anticipated in the NFD report prepared for specific substation construction or upgrade projects. Fortis argued that, notwithstanding these variances, its load forecasting methods were sound and generated reasonable results.

Forecasting Methodology

The AUC noted that Fortis's approach to forecasting with NFD documents for Needs Identification Document applications builds in capacity at the time that a specific project comes into service that is expected to be greater than the peak load forecasts for a specific year. On the basis of the evidence filed by Fortis and, in particular, its responses to AUC Information Requests, the AUC found this approach to be reasonable for the following reasons:

- Customers benefit from the use of standardized transformer sizes; and
- The costs of "oversizing" the capacity of a point of delivery ("POD") substation may be less than the costs of upgrading a POD substation multiple times.

Reasonableness of Fortis's Forecasts

The AUC agreed with Fortis that variances between the forecasts used by Fortis within NFDs for POD substation projects under consideration and the latest available actual feeder loading statistics reflected the effect of economic factors on end-use customers that Fortis could not have anticipated with any degree of certainty at the time it made key decisions on many projects.

However, the AUC found that the commitments required from end-use customers by Fortis are not sufficiently strong. Accordingly, the AUC directed Fortis to review its pro forma Electric Service Agreement as well as other measures to ensure that expenditures are not stranded, to ensure that end-use customers are provided with incentives sufficient to ensure that they request only the capacity that they reasonably expect to require and that sufficient safeguards are in place to guard against forecast risk, particularly where based on customer demand.

Projects with Costs Transferred from Cancelled Projects

The AUC asked a series of information requests that sought clarification of the treatment of costs in instances where a project with an identifiable name was initiated by Fortis but was either not completed, or where the initial work appeared to have been completed under a project with a different name.

For the South Mayerthorpe 443S Upgrade Project, Fortis was directed to apply an adjustment in the amount of negative $80,000 to the AESO contribution for the year 2016.

For the Blackfalds 198S substation, the cumulative AESO contribution capital addition amount of $1,312,636 was approved, as filed.

The AESO contribution amount of $10,146,678 for the year 2016 shown for Okotoks/High River Area Project was approved, as filed.

In Decision 24329-D01-2019, in respect of AltaLink's compliance filing pursuant to Decision 22542-D02-2019, the AUC made findings on the reasonableness of costs transferred from the Waiparous 639S project to the Cochrane 291S projects. AltaLink noted that Fortis had instructed it to transfer Waiparous project costs into the Cochrane project.

The AUC found that of costs totalling $2,494,111 that were transferred into the Cochrane 291S Upgrade Project from the Waiparous 639S project, only $739,526 was reasonable within the Cochrane 291S Upgrade Project. Accordingly, the AUC found that the balance of the costs transferred over totalling $1,754,585 ($2,494,111 – $739,526) should be recovered by AltaLink from Fortis in accordance with the applicable provisions of the construction commitment agreement for that project.

The AUC found that Fortis failed to explain why the costs beyond the $739,526 amount should be eligible for recovery. Therefore, Fortis was directed to apply an adjustment in the amount of negative $1,754,585 to Fortis's AESO contribution additions for the Cochrane 291S Upgrade Project for the year 2016 in its compliance filing.

The AUC asked Fortis why the capital tracker amounts totalling $5,594,361 in respect of the Edwards Lake 189S new substation project should not be reversed in light of the cancellation of the project. The AUC noted that notwithstanding Fortis's receipt of a refund in December 2018 related to the Edwards Lake 189S project as noted above, it was clear that Fortis was aware that this project was "on hold" by January 2016, and that it was formally advised by Canadian Natural Resources Limited on March 8, 2017, that the project would no longer be required.

Given the foregoing, the AUC found that in lieu of Fortis's proposal to make an adjustment reflecting the project cancellation as part of its next annual PBR rate adjustment application, the AESO contribution amounts of $3,200,000 in 2014 and $2,394,361 in 2015 should be reversed through an adjustment applied in 2016 in the amount of negative $5,594,361.

Reaccrual of Allowances for Funds Used During Construction

In Proceeding 22741, the AUC asked Fortis to confirm that its AESO contribution amounts had been updated to reflect the reaccrual of AFUDC to certain projects. In its response, Fortis indicated that it had not updated its projects to reflect the reaccrual of AFUDC and instead indicated that such reaccrual was expected to occur in 2017.

Fortis indicated that it had applied the reaccrual of AFUDC to many, but not all, of the projects. Specifically, Fortis explained that, as indicated in subsection 9.7(5) of the ISO tariff, the market participant is not required to pay, and the legal owner of the transmission facilities is not required to refund adjustments of less than $10,000.

The AUC was satisfied that AFUDC had been applied in a reasonable manner to the applicable projects. However, the AUC considered that this true-up should be applied as a pre-2016 true-up instead. The AUC considered that the application of the AFUDC true-up in respect of 2016 rather than 2017 has the effect of allowing the AFUDC to be reflected in the K-bar calculation for the 2013-2016 period, which applies risk-reward mechanism disallowances to 2016 rather than in 2017.

Risk-reward Mechanism Disallowances

In Decision 2013-407, the AUC disallowed AltaLink's request to include the costs of its proposed "risk-reward mechanism" in its forecast capital costs in its tariff application.

With the release of Decision 2013-407, all parties were aware that no risk-reward mechanism related costs should be included within any AltaLink capital projects. Fortis was directed to apply the risk-reward reductions totalling negative $1,222,085, as an adjustment to its 2016 AESO contribution amount.

Distribution Connected Generation

The AUC noted that the hybrid deferral account mechanism approved in Decision 23505-D01-2018 provides a means by which changes arising from the application of the substation fraction to Fortis POD substation projects can be recovered from Fortis's distribution connected generation ("DCG") customers. The AUC also agreed that in such events, the hybrid deferral account mechanism provides a means, on a go-forward basis, by which the benefits of amounts that are charged to Fortis's DCG customers can be provided to Fortis's load customers.

In Decision 22942-D02-2019, the AUC approved an AESO proposal to adopt an adjusted metering practice that would separately meter Demand Transmission Service ("DTS") and Supply Transmission Service energy on Distribution Facility Owner ("DFO") feeders located within the DFO substation grounds. The adoption of the adjusted metering practice is a change from the metering practice in respect of DCG applied by DFOs, including Fortis, whereby, the DTS energy amount entering the Alberta Interconnected Electric System ("AIES") had been metered on a "net" basis.

Given the approval of the AESO's grandfathering proposal in Decision 22942-D02-2019, the AUC's adoption of the AESO's adjusted metering practice in that decision will not require any adjustments to AESO contribution amounts for the years 2016 and 2017 within this decision.

Direction 5 from Decision 22741-D01-2018

In Decision 22741-D01-2018, the AUC issued Direction 5 to Fortis, as follows:

> Having regard for the above, and having regard for the Commission's finding in Section 7.1.2.1 that the projects in Attachment FAI-AUC-2017SEP07-002.01 are not final by virtue of Fortis' structural reliance on future refunds to be triggered by future DTS [demand transition service] increases, the Commission directs Fortis to recalculate AESO contributions for all projects in Attachment FAI-AUC-2017SEP07-002.01 to reflect the AESO contribution refund pursuant to subsection 2 of Section 9 of the ISO tariff that Fortis would be eligible for if it immediately increased DTS to the amount of the maximum capacity of the project. For this purpose, Fortis is directed to use the maximum DTS level indicated for each project in Fortis' response to FAI-AUC-2017SEP07-003, and to calculate the effect of such DTS contract capacity changes to determine a revised prior-year true-up for the year 2016. Fortis is directed to file this information in a compliance filing pursuant to this decision.

The AUC noted that Direction 5 from Decision 22741-D01-2018 was varied in conjunction with the adoption of the hybrid approach in Decision 23505-D01-2018. As such, the AUC noted that a CCA request for a refund of 50 percent of the amount calculated by Fortis in relation to the cost of complying with Direction 5 from Decision 22741-D01-2018 represented a collateral attack on that decision. The CCA's request was denied.

AUC's Conclusions on Criterion 1

Because of adjustments outlined in this decision, the AUC could not make a determination as to whether the AESO Contributions Program included in the 2016 and 2017 true-up satisfy the project assessment requirement of Criterion 1.

For the same reason, the AUC could not determine in this proceeding as to whether Fortis's AESO Contributions Program included in the 2016 and 2017 true-up satisfy the accounting test requirement of Criterion 1. The AUC directed Fortis, in its compliance filing pursuant to this decision, to revise its accounting test for 2016 and 2017, based on directions in this decision, and reassess whether the AESO Contributions Program included in the 2016 and 2017 true-up satisfy the accounting test requirement of Criterion 1.

Fortis's Compliance with AUC Directions from Decision 23505-D01-2018

The AUC reviewed Fortis's response to Direction 1 from Decision 23505-D01-2018 and was satisfied that Fortis has complied with the direction as it confirmed that it would implement the hybrid approach for incremental AESO contributions and has not changed its contracting practices.

The AUC also found that Fortis complied with Direction 2 from Decision 23505-D01-2018 with respect to filing of an application to finalize the 2016 and 2017 capital tracker amounts. However, the AUC directed Fortis to use the approved amounts to finalize its 2016 and 2017 capital tracker true ups and adjust its going-in rates and K-bar amounts for the 2018-2022 PBR plan.

Regulatory Burden Reduction - AUC Roundtable and Next Steps, AUC Bulletin 2019-18

Bulletin - Regulatory Burden Reduction

On October 4, 2019, the AUC held a roundtable with approximately 50 stakeholders to discuss regulatory burden and how future regulatory approaches might reduce or eliminate regulatory requirements.

What the AUC Heard and Intends to Address to Reduce or Remove Regulatory Burden

The AUC noted that stakeholders raised a number of specific suggestions for changes to the AUC's application and hearing processes. The recommended changes are identified as follows:

Adjudicative Hearings:

- Limit information requests to circumstances where fact-finding is required by applying existing Rule 001: *Rules of Practice*.
- More reliance on written proceedings.
- More reliance on oral argument.
- Scope constrained to early, clear and detailed issues development.
- Fixed decision dates with related incentives for parties' failure to comply with necessary steps to meet hearing date.
- Increased use of incentives to drive behavior in adjudicative proceedings through imposition of cost consequences in the cost recovery process.

Role of Parties:

- Clear demonstration of interest and how decisions impact the rights of constituencies, as a measure of standing.
- Greater engagement by Commission panels in challenging and supervising questions and submissions of parties.

Pre-hearing Processes:

- More use of technical conferences and less use of written interrogatories.

- Potential for Commission members attending technical conferences and ruling on relevance of questions, responsiveness of answers and need for undertakings.

- Greater use of negotiated settlements and guidance as to which issues should be settled and which should go to a hearing.

- Participation of Commission members in settlement discussions.

<u>Next Steps</u>

While the review identified themes and areas for further work, the AUC indicated it knows there are improvements that it can start now to reduce regulatory burden. The AUC stated that it is introducing the following changes immediately, where appropriate.

The AUC will make greater use of technical or pre-hearing meetings with the applicant and interveners to:

- define the scope and issues arising from the application;

- clarify content in an application with a view to reducing information requests;

- determine the relevance and adequacy of information requests and responses;

- schedule process steps with fixed dates, and especially fixed hearing dates; and

- deal with all interlocutory matters in an expedited fashion.

The AUC indicated it would attend these sessions and make a ruling on these matters shortly after the meeting.

The AUC stated that it would initially implement these measures in the following rates proceedings:

- ATCO Electric Transmission 2020-2022 General Tariff application;

- ENMAX Power Corporation 2019 Distribution Tariff, Phase II application; and

- ATCO Electric 2019 Distribution Tariff, Phase II application.

The AUC will also implement its proposed new measures in the following upcoming needs identification documents and transmission facility applications:

- Chapel Rock to Pincher Creek Transmission Development;

- Alberta – British Columbia Intertie Restoration; and

- Central East Transfer out.

The AUC indicated that it's Facilities Division would coordinate a roundtable meeting with representatives from Alberta Environment and Parks and renewable developers to identify and address overlap between the two agencies and discuss options for making the application process more flexible to address rapid technological change.

The AUC indicated that it will continue to examine the areas identified for future work and looks forward to continuing its discussions with stakeholders.

The AUC stated that it is vitally important that everyone who participates in the regulatory sector accept responsibility to adapt to the changes being implemented. The AUC cautioned that not all would be easy to implement. For example, an AUC letter directing a party to appear in four days to argue the relevance or adequacy of information requests is very different from the current written process. However, the AUC noted that without this kind of dramatic process change, we risk making little if any progress on reducing regulatory burden.

***Town of Devon - Appeal of Water Rates by Imperial Enterprises Inc.*, AUC Decision 24435-D01-2019**

Water Rates

In this decision, the AUC found pursuant to Section 43 of the *Municipal Government Act* ("*MGA*") that certain water rates charged to Imperial Enterprises Inc. ("Imperial") from January 1, 2019, to present, were discriminatory.

<u>Introduction</u>

In Decision 22785-D01-2018, the AUC ruled that the Town of Devon ("Devon") had improperly imposed an increase in water rates charged to Imperial. The AUC found that the increased rates were established by resolution and not by bylaw, as required by the statutory framework set out in the *MGA*. The subject of this proceeding was a subsequent appeal from Imperial that Devon's bulk water service rates that came into effect on January 1, 2019, were discriminatory.

Devon owns and operates a municipal water utility system that treats water from the North Saskatchewan River, and then delivers potable water to customers through its distribution system. In addition to providing water to metered customers on its distribution system, Devon provides bulk water to two independent entities:

(a) Imperial, which purchases water from Devon and either resells or delivers the water to its consumers through facilities owned by Imperial; and

(b) Sprucedale Water Co-op ("Sprucedale"), which provides water to its members through its own distribution system that is connected to Devon's water distribution system.

Devon also sells bulk water from its own bulk station through key lock accounts and coin-operated dispensers.

Water Rates, Utility Bylaw and the Appeal Application

On November 13, 2018, Devon passed two bylaws, Bylaw 919/2018 Water Rates Bylaw ("Water Rates Bylaw"), which set rates for water services provided by Devon commencing January 1, 2019, and Bylaw 917/2018 "Amending Bylaw to Utility Bylaw 836/2010 & Amendment Bylaw 903/2017" ("Utility Bylaw"), which governs utility service in Devon.

The complaint by Imperial related specifically to the rates set by Devon for bulk water services, which is reproduced below from Schedule A of the Water Rates Bylaw (Section 1 has not been reproduced herein):

2 Bulk Water Service Rates

The charges for unmetered and bulk water shall be computed and rendered monthly as follows:

(a) Keylock Accounts

(**i) Monthly Charge** - When water is supplied during any month, a monthly charge of $10.00 per month shall apply.

(ii) Water Commodity Charge - A commodity charge of $4.75 per cubic meter of water supplied.

(iii) Sprucedale Water Co-op - A commodity charge of $2.72 per cubic meter of water supplied.

(b) Coin-operated Water Dispenser

(i) Commodity Water Charge - A commodity charge of $4.75 per cubic meter.

(c) Private Bulk Water Stations

(i) Metered Consumption - A commodity charge of $4.75 per cubic meter.

(**ii) Basic Monthly Charge** A basic monthly charge based on service pipe size per section 1(a) of this Schedule.

Imperial paid a basic monthly charge of $48.67 for its incoming 100 millimetres (mm) water line under Schedule A, sections 1(a) and 2(c)(ii) of the Water Rates Bylaw, plus a commodity charge of $4.75 per cubic metre ($m^3$) under Section 2(c).

In its appeal, Imperial submitted that the commodity charge of $4.75/$m^3$ was discriminatory, and the private bulk water service rate was directed only at Imperial, as it is the only private business selling bulk water in Devon. Imperial stated it has operated a bulk water station since 2003, and its commodity charges had been increasing since July 2015.

Further, Imperial submitted that Devon is selling bulk water from its own competing facility for the same price as it sells to Imperial and that Devon must have known this would put it out of business. Imperial noted that bulk water was also provided to Sprucedale, at a rate of $2.72/$m^3$.

Imperial stated Devon is "unfairly competing," in that:

- Devon sets the price on wholesale bulk water.
- Devon sets the price on retail bulk water and is able to set that price without the need for profit or consideration of operating costs.

- Devon set the price of retail bulk water to the same price they charge themselves for it.

- It is unknown whether or not Devon charges themselves for the incoming line charge, which occurs monthly for Imperial, or if Devon has accurate cost accounting for the maintenance and operation of their bulk station.

Imperial submitted that it is in the same or similar class as Sprucedale, and should be afforded the same rates.

The AUC's Authority

The AUC noted that its authority to deal with this matter is set out in Section 43 of the *MGA*, which states:

> Appeal
>
> 43(1) A person who uses, receives or pays for a municipal utility service may appeal a service charge, rate or toll made in respect of it to the Alberta Utilities Commission, but may not challenge the public utility rate structure itself.
>
> (2) If the Alberta Utilities Commission is satisfied that the person's service charge, rate or toll
>
> (a) does not conform to the public utility rate structure established by the municipality,
>
> (b) has been improperly imposed, or
>
> (c) is discriminatory,
>
> the Commission may order the charge, rate or toll to be wholly or partly varied, adjusted or disallowed.

Discrimination

In assessing an appeal under Section 43(2)(c) of the *MGA*, the AUC had previously held that discrimination could arise in two circumstances:

- First, when a utility fails to treat all its users equally where no reasonable distinction can be found between those favoured and those not favoured.

- Second, when a utility treats all its users equally where differences between users would justify different treatment.

In determining whether Devon's bulk water service rate was discriminatory, the AUC considered whether there was a reasonable distinction between Imperial and other customers, and whether this distinction supported different treatment.

AUC Findings

The Commission found that Imperial's water rates were discriminatory because while the Water Rate Bylaw distinguished between private bulk water stations and other customers, it was not apparent based on a plain reading of either the Utility Bylaw or the Water Rate Bylaw that the differing treatment between customers was supported. The AUC considered the water rates discriminatory given:

- The difficulty in identifying the distinction between the characteristics of different customer classes in both the Water Rate Bylaw and Utility Bylaw.

- The lack of distinguishing factors between a metered water customer under subsections 1(a) and (b) of Schedule A and the bulk water customers under Section 2 in the Water Rate Bylaw.

- The lack of transparency of water volume differences in charging water rates under the Water Rate Bylaw and Utility Bylaw.

- The insufficient language in the Water Rate Bylaw to support different rates charged to Imperial under Section 2(c) of Schedule A compared to other rates charged under Section 2.

First, the AUC noted there was a lack of distinction between the characteristics of different customers under the Utility Bylaw and the Water Rates Bylaw that addressed water utility rates. Devon's attempt to draw distinctions between customers as "retail", "wholesale" and "bulk" was not supported by the Utility Bylaw or Water Rates Bylaw, which had no definitions for these classes of customers.

Second, the AUC examined the Water Rates Bylaw and found the only distinction provided in Section 1 of Schedule A was metered service pipe size. A plain reading of both bylaws did not set out distinguishing characteristics to differentiate Imperial as a customer who was charged differently than customers who paid metered water rates under Section 1(b), or customers who paid bulk water service rates under the different categories of Section 2 of Schedule A of the Water Rates Bylaw. The fact that Imperial is charged a basic monthly charge under the "Metered Service Pipe Size" further confused the treatment of Imperial.

Third, the AUC had concerns with the submissions of Devon on distinguishing between classes of customers based on water volume, which was not clearly reflected in the Water Rates Bylaw or the Utility Bylaw.

Based on Devon's submissions, there were no limits imposed on any retail customer in the normal course of operations unless there was a separate customer agreement in place. Devon also confirmed that no water volume limits were placed on Imperial. It was not apparent to the AUC how "no limitations or restrictions as to rates of flow or annual volumes" is reflected in the bulk water service rates charged to Imperial given the much lower commodity charge for metered water rate customers. Further, it appeared that the only limit to the receipt of water volumes were the limitations imposed by the capacity of the distribution system to provide that supply. Devon did not highlight any specific capacity limitations or constraints that may be exceeded to support the commodity charge levied on Imperial.

For these reasons, the AUC found that Devon's submissions on water volumes as a reason why Imperial was charged a different bulk water service rate was not persuasive nor was water volume a distinguishing factor in differentiating the commodity charges to Imperial under the private bulk water stations rate included in the Water Rate Bylaw.

Fourth, with respect to different customer rates charged under Section 2 of the Water Rates Bylaw, Devon submitted that "… customers accessing the Devon bulk water fill station pay all costs associated with their volume taken through the commodity charge …" However, the AUC noted that Imperial was subject to a separate basic monthly charge based on the size of its service line.

Imperial was charged a fixed and variable rate for bulk water service under Section 2(c) of the Water Rates Bylaw. Other bulk customers were not charged a basic monthly charge under Section 2 of the Water Rates Bylaw. However, under the Water Rates Bylaw, Imperial paid the same commodity charge as other bulk customers, which included all costs of providing service.

In addition, Imperial paid a basic monthly charge, which included demand costs. Thus, it appeared that Imperial was paying for the demand cost twice, suggesting discriminatory treatment of Imperial.

Based on the AUC's findings, it could not identify a reasonable distinction between Imperial and other customers sufficient to justify the differential rates charged to Imperial.

The AUC found water commodity charged to Imperial under Section 2(c)(i) of Schedule A of the Water Rate Bylaw to be discriminatory.

<u>Relief</u>

Pursuant to Section 43 of the *MGA*, if a person's rate is found to be discriminatory, the AUC may order the rate to be wholly or partly varied, adjusted or disallowed. Applying its discretion to determine the relief to Imperial, the AUC found that Imperial should have been charged a commodity rate of $1.55/m^3. Imperial's basic monthly charge remained unchanged as a result of this decision.

As a result, the AUC directed that Devon recalculate Imperial's bulk water service rates based on a commodity charge of $1.55/m^3, effective January 1, 2019. It further ordered that Devon shall refund the difference of $4.75/m^3 and $1.55/m^3 in commodity charges to Imperial, for all water volumes consumed from January 1, 2019, to the date of the issuance of this decision.

***Village of Delia Appeal of Utility Charges by Heide Peterson and Yvon Fournier*, AUC Decision 24678-D01-2019**

Municipal Utility Rates - Appeal

In this decision, the AUC considered an appeal from Ms. Heide Peterson and Mr. Yvon Fournier (collectively, the "Appellants"), requesting that the AUC disallow all water, sewer, garbage and land fill utility charges, including interest, from June 1, 2018, to July 1, 2019, that the Village of Delia ("Delia") had applied to Mr. Fournier's utility account. The AUC found that certain of the water, sewer, garbage and land fill service charges at issue in this appeal, from June 1, 2018, to present, were discriminatory and therefore ordered that Delia not pursue these charges.

Background

The Appellants own a commercial property (the "Property") in Delia. From 1980 to May 2017, the Property was vacant and not receiving utility service. However, commencing in June 2017, the Property was leased to a commercial business for a one-year term (the "Lease"). The Appellants requested that Delia provide utility service to the Property and provided a copy of an application for utility services for the Property, dated July 31, 2017.

When the Lease ended, and the Property was once again vacant, Ms. Peterson informed Delia they no longer required utility services at the Property. Water service to the Property was disconnected at the end of May 2018. However, Ms. Peterson submitted that Delia informed the Appellants that, regardless of the disconnection of water service, they were still required to pay for utility services, pursuant to Section 9 of Bylaw #623-2017. Bylaw #623-2017 required that from April 17, 2017, onward, an owner is responsible for all service charges, fees and other charges whether water service is connected or has been disconnected.

AUC Jurisdiction

The AUC's jurisdiction to deal with this matter is set out in Section 43 of the *Municipal Government Act*, which states:

> **Appeal**
>
> **43(1)** A person who uses, receives or pays for a municipal utility service may appeal a service charge, rate or toll made in respect of it to the Alberta Utilities Commission, but may not challenge the public utility rate structure itself.
>
> **(2)** If the Alberta Utilities Commission is satisfied that the person's service charge, rate or toll
>
> > (a) does not conform to the public utility rate structure established by the municipality,
> >
> > (b) has been improperly imposed, or
> >
> > (c) is discriminatory,
>
> the Commission may order the charge, rate or toll to be wholly or partly varied, adjusted or disallowed.

AUC Findings

The AUC noted that Delia customers that connected and then disconnected their water service prior to April 27, 2017, are not required to pay monthly non-metered charges, while customers that disconnected or both connected and disconnected their water service on or after April 27, 2017, are required to pay monthly non-metered charges.

The AUC indicated it did not consider that Delia had established a reasonable basis for the distinction in billing customers monthly non-metered charges based on whether they disconnected from water service prior to April 27, 2017, or on or after April 27, 2017. Accordingly, the AUC found that Delia's rates were discriminatory.

The AUC ordered Delia to repay Mr. Fournier, the utility account holder, any amounts paid from June 1, 2018, to the date of the issuance of this decision, for any non-metered monthly charges for each of water, sewer, garbage and land fill service, in addition to any interest or penalties that Delia may have charged on these amounts. In cases where Mr. Fournier had not paid these charges, the AUC directed that Delia shall not pursue the recovery of these charges.

CANADA ENERGY REGULATOR

Nova Gas Transmission Ltd. Application for North Central Corridor Loop, CER October 15, 2019 Letter Decision

Facilities -Gas Pipeline

In this decision the CER considered an application from Nova Gas Transmission Ltd ("NGTL") for approval of its North Central Corridor Loop (North Start Section 1) Project (the "Project"). The CER approved the Project.

Background

The Project would consist of approximately 31.1 km of Nominal Pipe Size ("NPS") 48 pipe and a launcher facility for the purposes of in-line inspection. The Project would parallel existing disturbance, including the existing North Star Section pipeline, for approximately 97.7% of the Project route, starting from NGTL's existing Meikle Compressor Station and ending at an existing block valve site.

The Project would require approximately 57.5 hectares ("ha") of new permanent land rights and approximately 84.3 ha for temporary workspace. The proposed Right-of-Way ("ROW") would cross 11 tributaries to the Hotchkiss River, four drainages and two borrow pits that have become naturalized wetlands. Approximately 14.9 km of the Project would be located within the Chinchaga Caribou Range for which Environment and Climate Change Canada's Recovery Strategy for the Woodland Caribou ("Recovery Strategy") applies. The Project would parallel existing disturbance for its entire length with the range.

NGTL submitted that the purpose of the Project is to meet North Central Corridor Loop design flow requirements, which have been determined to exceed the capacity of the NGTL System in 2020.

CER Findings

Environmental Matters

NGTL's Environmental and Socio-economic Assessment ("ESA") properly analyzed and characterized the level of significance of potential adverse environmental effects as a result of the Project as outlined in the Filing Manual. Therefore, the CER found NGTL's ESA methodology was acceptable.

The CER assessed the environmental effects of the Project and found that the standard mitigation proposed and commitments made by NGTL would minimize the environmental effects of the Project.

The CER acknowledged NGTL's routing of the pipeline along existing linear disturbances, which avoids and minimizes disturbance to caribou habitat. The CER indicated it had consulted with the competent minister and considered the impact on the species' critical habitat. The CER was of the view that, with the mitigation proposed by NGTL and various conditions relating to future reporting requirements imposed by the CER, the impacts of the Project to caribou would be minimized.

Issues and Concerns Raised by Indigenous Peoples

The CER reviewed and considered NGTL's activities to engage Indigenous peoples and learn about their respective concerns and interests. The CER was satisfied that all potentially impacted Indigenous peoples had been notified and given the opportunity to comment on the Project. Further, the CER was of the view that the process provided for here was appropriate to the scope and scale of the Project and that there had been adequate consultation for the purpose of the CER's decision on this Project. The CER did, however, impose conditions to ensure NGTL's ongoing consultation with Indigenous peoples consulted on the Project.

The CER agreed that NGTL made reasonable opportunities (e.g., facilitating and funding Project-specific Indigenous knowledge studies, including fieldwork) available to potentially affected Indigenous peoples to identify any concerns regarding Project impacts to traditional land and resource use. Indigenous peoples have not raised any outstanding specific sites, resources or activities within the Project footprint that would require specific mitigation beyond what NGTL proposed.

Operations

The CER considered NGTL's request for an exemption from the requirements of paragraph 30(1)(b) and subsection 47(1) of the *NEB Act* to obtain leave to open ("LTO") from the CER prior to installing and placing into operation three tie-in assemblies. The CER approved NGTL's request for a partial exemption from applying for LTO.