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, consistent with public interest requirements. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

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ALBERTA COURT OF APPEAL

***Alberta Electric System Operator v Kalina Distributed Power Ltd.,* 2021 ABCA 354**

Addition as Party - Parties to Permission to Appeal Application

In this decision, the Alberta Court of Appeal ("ABCA") granted the application from the Alberta Electric System Operator ("AESO") to be added as a respondent to an application for permission to appeal Alberta Utilities Commission ("AUC") Decision 26090-D01-2021 re *FortisAlberta Inc. Distribution-Connected Generation Credit Module for Fortis's 2022 Phase II Distribution Tariff Application* (the "DCG Credit Decision").

Background

FortisAlberta Inc. ("FortisAB") filed an application with the AUC, seeking approval of its 2022 Phase II distribution tariff. The AUC decided to bifurcate that proceeding to address DCG credit-related matters in a separate proceeding. In the DCG Credit Decision, the AUC had directed FortisAB, ATCO Electric Ltd. ("AE") and ENMAX Power Corp. ("ENMAX") to file amendments to eliminate the DCG credit tariff provisions from their tariffs over a five-year period on a sliding scale.

Kalina Distributed Power Limited, Lionstooth Energy Inc., Signalta Resources Limited, and Campus Energy Partners L.P. (collectively "KLSC") sought permission to appeal the DCG Credit Decision alleging multiple errors of law and jurisdiction.

AESO's Application to be Added as a Respondent or Intervenor

Rule 14.57 states that parties may be added to an appeal in accordance with Rule 3.74, which permits parties to be added by the Court on application where "the Court is satisfied the order should be made". Under Rule 14.37 and 14.58, applications to intervene must establish that the applicant will (i) be directly and significantly affected by the appeal's outcome; and (ii) provide some expertise or fresh perspective that will be helpful in resolving the appeal.

As underlined in *Balancing Pool v ENMAX Energy Corporation*, 2018 ABCA 143, the ABCA has generally discouraged applications to be added at the permission to appeal stage of a proceeding, and this relief will only be granted in extraordinary circumstances.

Test to be Added as a Party

To be added as a party respondent, the AESO had to show (i) it has a legal interest in the matter; (ii) it is just and convenient; and (iii) its interest would be adequately protected only if it was granted party status.

The ABCA was satisfied that the AESO had shown that it has a legal interest in the outcome of the proceeding, as its statutory mandate regarding the operation of the interconnected electric system and the promotion of a fair, efficient and openly competitive electricity market will be impacted by the review of the DCG Credit Decision.

The ABCA further found that it is just and convenient to add the AESO as a party as the issues raised by KLSC involve matters where the AUC referred in part to evidence or submissions presented by the AESO on issues which relate to the AESO's statutory mandate. The ABCA finally found that the AESO will bring a valuable perspective to the application and any following proceeding as only the AESO and the AUC have a public interest mandate. Accordingly, it may be expected that the AESO's perspective is not identical to those of the distribution utilities. The AESO demonstrated that it meets all criteria to be added as a participant at the appeal stage of a proceeding.

Conclusion

The ABCA determined that in this case, the extraordinary circumstances justifying the addition of a party at this stage in a proceeding were present. The AESO has a legal interest in the matter, was a full participant in the prior proceeding, and will be a participant in the other permission to appeal application being heard on the same day arising out of the same proceeding and will bring a unique perspective.

The application was granted, and the AESO was added as a respondent.

AltaLink Management Ltd. v Alberta (Utilities Commission), 2021 ABCA 342

Costs – First Nations

In this decision, the Alberta Court of Appeal ("ABCA") allowed the appeal of Alberta Utilites Commission ("AUC") Decision 22612-D01-2018 (the "Decision") and directed the AUC to allow two limited partnerships, ultimately controlled by the Piikani Nation and the Blood Tribe (the "Partnerships"), to pass on audit and hearing costs they incur as utility owners to ratepayers.

Questions Presented

In the Decision, the AUC found that its approval of the electrical transmission asset transfers from AltaLink Mangagement Ltd. ("AML") to the Partnerships would result in incremental costs to the ratepayers. The AUC refused to allow the Partnerships to pass on audit fees and AUC hearing costs, estimated to be $60,000 to ratepayers.

AML as the transferor of the transmission assets was granted permission to appeal on two issues: First, did the AUC improperly fetter its discretion when considering the transfer by applying the "no-harm test"; and second, did the AUC err by failing to consider all relevant factors.

AML argued that the AUC must, when exercising its authority, take into account the honour of the Crown principle and the reconciliation concept.

The ABCA determined that the AUC's decision to ignore the cost savings arising from the routing of the transmission lines across the reserves of the Piikani Nation and the Blood Tribe is an error of law. The AUC did not consider all relevant facts when considering if a sale is in the public interest, which constitutes a legal error.

Background and Facts

In 2005, the Alberta Energy and Utilities Board approved the expansion of the electric transmission system in southwestern Alberta applied for by AltaLink Limited Partnership. As part of this proceeding, three route alternatives were considered, and AltaLink Limited Partnership presented one as its preferred route. Among other factors, that alternative was preferred as it was the shortest and lowest cost route. This alternative crossed the lands of the Piikani Indian Reserve No. 147 and the Blood Indian Reserve No. 148.

Before AltaLink Limited Partnership submitted its application, the Piikani First Nation and the Blood Tribe passed resolutions approving the specific routing across their reserves. Later, both First Nations exercised their options to purchase a fifty-one percent interest in the transmission line on their lands.

In the Decision, the AUC approved the transfer of the transmission assets to the Partnerships. As a condition of the approval, the AUC stated that the Partnerships cannot recover $60,000 in external auditor and hearing costs incurred for regulatory proceedings from ratepayers as part of their tariffs.

In its Decision, the AUC applied its "no-harm test". The AUC focused on whether the sale would impact the rates and reliability of the utility service for ratepayers. The AUC was concerned about the financial impact of the transaction. Specifically by incrementally recurring annual audit fees paid to external auditors and hearing costs that would not arise if AML was to continue the operation of the assets. It weighed this negative effect against the potential benefits of savings from the shorter, less expensive route and intangible benefits arising from the partnership with the First Nations. The AUC found that the benefits did not mitigate the financial harm to ratepayers from incremental costs. However, the harm could be mitigated by imposing a condition that the audit and hearing costs may not be recovered from ratepayers.

AML applied to the ABCA seeking an order directing the AUC to vary the Decision to allow the Partnerships to include the costs in question in their respective tariffs, or, alternatively, an order quashing the Decision and remitting it back for reconsideration.

ABCA Analysis

The AUC Erred by Considering Only Forward-Looking Considerations

In its application of the no-harm test, the AUC rejected the potential past savings arising from the transmission line's routing on First Nations lands and the intangible benefits AML suggested arose from the Partnerships. The first benefit was rejected on the basis that the no-harm test is forward-looking. The second benefit was rejected with the explanation that it could, as an intangible benefit, not be quantified.

The ABCA determined that the AUC erred in considering only forward-looking benefits. There is no legislative basis or rationale for this strict approach as an absolute rule. Further, the ABCA determined that the AUC had erred when determining that cost savings solely from the initial construction phase are irrelevant.

The ABCA determined that a much broader view of the no-harm test and the public interest was appropriate. Particularly, the approach included factors the AUC considers relevant to the transfer and sale application, even if they arise before the application.

While making this finding, the ABCA noted that a forward-looking approach would result in consideration of all relevant public interest factors most of the time. Projects that increase economic activity on a reserve ought to be encouraged. They are in the public interest. This project explicitly contemplated such activity.

As the ABCA found the AUC to have made an error in this respect and only one error is needed for the appeal to be granted, it did not consider the second issue.

Conclusion

The appeal was allowed. As requested by AML, the ABCA varied Decision 22612-D01-2018 by ordering that the PiikaniLink Limited Partnership and the KainaiLink Limited Partnership may include the incremental audit and hearing costs in their respective tariff applications.

***The Office of the Utilities Consumer Advocate v Alberta Utilities Commission,* 2021 ABCA 336**
GCOC – COVID-19

In this decision, the Alberta Court of Appeal ("ABCA") dismissed an application for permission to appeal Alberta Utilities Commission ("AUC") Decision 26212-D01-2021 regarding generic cost of capital, filed by the Utilities Consumer Advocate ("UCA") pursuant to Section 29 of the *Alberta Utilities Commission Act* ("*AUC Act*").

Background

In Decision 26212-D01-2021 (the "Decision"), the AUC determined the 2022 generic costs of capital for ATCO Electric Ltd, ATCO Gas and Pipelines Ltd, AltaLink LP, and EPCOR Distribution & Transmission Inc (the "Utility Companies"). Considering the Covid-19 pandemic, before establishing a process, the AUC asked whether there was enough ground for a further extension of the 2021 parameters for return on equity ("ROE") and equity ratio for 2022 and if a return to a more traditional approach was possible.

The Utility Companies predominantly requested extending the ROE and equity ratios and dispensing with a proceeding for 2022. Interveners, including the applicant, generally opposed that view.

The AUC was of the view that the economic and market data available at the time was uncertain and remained in flux. It determined that there was an inadequate basis to depart from the approved ROE and equity thickness. A fair return for 2022 was set at the same level as was approved for 2021.

The UCA sought permission to appeal on two questions:

- Did the AUC err in law or jurisdiction by failing to undertake its statutory obligation to set a fair return for 2022, including by applying the incorrect test and considering irrelevant factors? (the "Fair Return Issue")

- Did the AUC err in law by breaching its duty of procedural fairness in setting a fair return for 2022? (the "Procedural Fairness Issue")

<u>Discussion</u>

Fair Return Issue

The AUC, in setting just and reasonable rates, is required to set a fair return for the utilities it regulates. In applying the Supreme Court of Canada's decision *Northwestern Utilities Ltd v Edmonton (City)*, [1929] SCR 186, the Commission has held that when determining the fair return, it must consider capital attraction, financial integrity and comparable investments, described as the Fair Return Standard.

The ABCA found that the AUC had a statutory discretion to select the method, procedure and evidence it considered appropriate to determine a fair return. The AUC was not required to utilize the intensive process it had used at times past; it could adopt an alternative approach, particularly in light of the COVID-19 pandemic and an alternative approach was not an error of law.

The ABCA further found that the AUC is given a wide discretion to consider all the facts it finds relevant in exercising its statutory mandate. These decisions involve questions of mixed fact and law. The Decision shows that the AUC sought to balance factors in deciding what was fair to the utilities and to customers given the uncertainty resulting from the pandemic. Such a decision would be reviewed by this Court on a standard of reasonableness.

In conclusion the ABCA found that the AUC did not make an error in law. In settling a utilities' fair return, the AUC is empowered to weigh the evidence and exercise its judgment, which it did in this case.

Procedural Fairness Issue

The ABCA found that the merits of the Procedural Fairness Issue were undermined by the applicant's assertion that the AUC failed to determine and conduct a process, as the AUC did determine and conduct this process. The ABCA found that the applicant's complaint is a variation of its first issue, that the AUC did not conduct an intensive approach to the proceeding.

The procedure was different from that of previous approaches, but all parties were given notice, and the applicant was given the same opportunities as all other parties. The UCA's complaint to the ABCA that it was not afforded an opportunity to answer the case made against it nor to correct statements of fact prejudicial to its view ignored that AUC proceedings are not dispute-based, and parties do not have a right to reply. The UCA was not denied any procedural rights.

<u>Conclusion</u>

Neither issue raised questions of law permitting the ABCA to grant permission to appeal. The UCA's application for permission to appeal was dismissed.

ALBERTA ENERGY REGULATOR

New Alberta Environment and Parks Directive for In Situ Projects with Non-saline Groundwater in Contact with Bitumen, AER Bulletin 2021-39

Oil and Gas - AEP Directive

On September 29, 2021, Alberta Environment and Parks ("AEP") issued *Directive for the Assessment of Non-saline Groundwater in Direct Contact with Bitumen for In Situ Operations*. This directive sets out requirements that in situ operators that hold or are applying for approval under the *Environmental Protection and Enhancement Act* must follow for assessing and managing non-saline groundwater in contact with bitumen.

New Functionality Moving to One Stop, AER Bulletin 2021-40 and Bulletin 2021-41

Public Lands – Aggregate Management Plans

The Alberta Energy Regulator ("AER") announced that the OneStop Platform will receive new functionalities. Details on enhancements and fixes will be available with implementing the new functionalities on the OneStop webpage under "Enhancements and Fixes".

Enhanced Search (Elasticsearch) Function

Users will have greater flexibility when searching for information. The enhancements include additional filter and search fields. The enhancements aim to increase the speed and quality of the results.

Submissions

The submission functionality has been enhanced to support notifications and alerts. Further, an option for interested stakeholders to receive e-mail notifications on new submission types and the ability to generate Enterprise Submissions Summary reports.

Aggregate Management Plans (Submission Type)

Disposition holders required to submit aggregate management plans ("AMPs") or annual aggregate plan updates will be expected to submit them through OneStop after October 21, 2021.

Public Lands

Manual 018: OneStop Public Lands Application will be updated to include guidance on the application process for borrow pit dispositions issued by the AER. Further, applicants will be able to apply for amended or new surface material dispositions under the AER's jurisdiction, including the regulator surface materials lease ("RML"), regulator surface materials license and the regulator surface materials exploration.

Applicants will be able to renew RMLs. They will also be able to provide site entry notification, no-entry cancellation notification, and plan replacement submissions for surface material dispositions.

The Master Schedule of Standards and Conditions logic in OneStop will be updated to accommodate surface material applications. Finally, related to public lands, all draft *Public Lands Act* applications will require updated variance information before submission if they contain variances to standards.

Well Directional Surveys

Licensees will also be able to submit directional survey data through OneStop. The AER no longer accepts directional survey PDF data submitted by e-mail.

***New Contamination Management Manual*, AER Bulletin 2021-42**
Oil and Gas

In Bulletin 2021-42, the Alberta Energy Regulator ("AER") announced *Manual 021: Contamination Management*. The purpose of this manual is to assist the industry in understanding the regulatory requirements and expectations for remediating contamination related to oil and gas, in situ, and pipeline activities regulated by the AER. It follows the requirements of the *Remediation Regulation* and does not introduce any new requirements.

***Request for Stay by Lac Ste. Anne Métis Bonavista Energy Corporation,* AER Request for Regulatory Appeal No. 1934267**
Regulatory Appeal - Irreparable Harm

In this decision, the Alberta Energy Regulator ("AER") approved an application from the Lac Ste. Anne Métis community ("LSAM") for an extension of the timeline to file a request for regulatory appeal ("RRA") of Approval No. RTF 216384 ("Temporary Access Disposition"). The AER however denied the request from LSAM to stay Approval No. 1934267 (the "Facility Licence").

<u>Late Filing</u>

The AER noted that the applications for the temporary field authorization ("TFA") were submitted as routine and were therefore approved expeditiously. The AER further noted that this significantly reduced LSAM's opportunity to file a statement of concern. In this proceeding, LSAM filed their request for regulatory appeal seven days late. Bonavista Energy Corporation ("Bonavista") has not alleged that this delay would prejudice them. Moreover, this delay allowed for the Facility Licence and the TFA to be filed together, which is more efficient administratively. The AER therefore granted the request to file the request for a regulatory appeal of the TFA late.

<u>Stay Request</u>

The AER may grant a stay on the request of a party to a regulatory appeal under section 39(2) of the *Responsible Energy Development Act*. The applicant for a stay must demonstrate that there is a serious question to be tried, that there will be irreparable harm if the stay is not granted, and that the balance of convenience favours granting a stay of the original decision.

Serious Question

The AER was unable to properly determine if the participant involvement requirements had been met. As a result, and because Bonavista's activities occur in proximity to areas confirmed by LSAM to be critically important, the AER was satisfied that there is a serious issue to be tried and that the requested appeal is not frivolous or vexatious.

Irreparable Harm

Irreparable harm will occur if the stay applicant is adversely affected by the conduct the stay would prevent if the applicant ultimately prevailed on the regulatory appeal. The harm must be of a nature that cannot be remedied through damages or otherwise cured. It must be of such a nature that to refuse the stay would be a denial of justice.

The AER found that LSAM did not demonstrate that they may suffer any harm at all because of the stay not being granted.The AER found that LSAM did not provide any evidence on how the facility would cause irreparable harm. This was supported by the fact that the facility licence would only be adding to an existing mineral surface lease. LSAM provided only general arguments as to how industry activities may affect traditional land use. LSAM did show that its traditional land use rights could be affected by the permanent installation of the facility. However, LSAM did not provide evidence that the facility was a permanent fixture of the land that could not be uninstalled and remediated if LSAM was ultimately successful in its appeal.

Balance of Convenience

The balance of convenience involves examining which party will suffer more harm from granting or refusing the stay. The AER must weigh the burden the stay would impose on Bonavista against the benefit LSAM will receive from a stay. This requires the AER to consider significant factors and not just perform a cost-benefit analysis. The AER determined that LSAM did not demonstrate that a balance of convenience favours the AER granting the stay. The AER noted that a stay on the facility license would require changes to how the existing wells would be produced. Considering the benefit to LSAM, the AUC held that it was unclear how the facility's construction, pending the result of the appeal, would affect the rights of LSAM any more than Bonavista's already existing developments on the site

ALBERTA UTILITIES COMMISSION

***Agrium Inc. Redwater Nitrogen Operations Cogeneration Plant,* AUC Decision 26825-D01-2021**
Cogeneration - Facilities

In this decision, the Alberta Utilities Commission ("AUC") approved an application from Agrium Inc. to construct and operate a 30-megawatt ("MW") cogeneration power plant, the Redwater Nitrogen Operations Cogeneration Plant (the "Power Plant"), within the existing Redwater Fertilizer Manufacturing Plant, located near Redwater.

Application

The Power Plant will include two 15 MW gas turbine generators and waste heat recovered steam production from two heat recovery steam generators. Agrium Inc. stated that the power will not be exported to the Alberta Interconnected Electric System and would stay on the internal system of the Redwater Fertilizer Manufacturing Plant.

Discussion and Findings

The AUC determined that the application met the information requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.*

Regarding noise control, the submitted noise impact assessment ("NIA") indicated that the cumulative sound levels exceeded the permissible levels at four receptors. The minor exceedances were attributed to the fact that the corresponding baseline sound levels already exceeded the permissible sound levels. The AUC determined that the NIA demonstrated the project is expected to comply with the no-net-increase requirement for noise from new facilities in the Alberta Industrial Heartland.

The air quality assessment indicated that the 24-hour $PM_{2.5}$ concentrations under the Base Case Maximum Emissions scenario and Application Case Maximum Emissions scenario exceeded the *Alberta Ambient Air Quality Objectives and Guidelines* by 0.5 per cent. This exceedance occurred for one receptor for one day over the five-year period and indicated a maximum predicted concentration associated with the Power Plant's emissions of less than or equal to 0.1 per cent. The AUC agreed that the Power Plant's effect on air quality is not significant.

The AUC determined that the application is in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act.* Pursuant to Section 11 of the *Hydro and Electric Energy Act,* the AUC approved the application to construct and operate the Power Plant.

***Alberta Electric System Operator Enterprise Solar Interconnection Project,* AUC Decision 26785-D01-2021**
Facilities - Solar

In this decision, the Alberta Utilities Commission ("AUC") approved a needs identification document ("NID") application from the Alberta Electric System Operator ("AESO"). It further approved three of four facility applications from Enterprise Solar GP Inc. ("Enterprise") and AltaLink Management Ltd. ("AML") for the proposed Enterprise Solar Interconnection Project (the "Project").

Applications

Enterprise has approval from the AUC to construct and operate a 65-megawatt ("MW") solar power plant designated as the Enterprise Solar Project (the "Power Plant") in the Vulcan area. The applications in this proceeding seek approval of the need for, and the facilities required, to connect the Power Plant to the Alberta Interconnected Electric System ("AIES").

AESO NID Application

The AESO's needs application was filed in response to Enterprise's request for system access service to connect the Power Plant to the AIES. The AUC found that the NID application met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*. In accordance with subsection 38(e) of the *Transmission Regulation,* the AUC determined the assessment of the need to be correct and approved the NID application.

Enterprise Solar's Facility Applications

Enterprise applied to meet the need by constructing a 35-meter-long, 138-kV transmission line to connect its approved substation to AML's Transmission Line 161L, under the Market Participant Choice option, pursuant to section 24.31 of the *Transmission Regulation*.

The AUC was satisfied that Enterprise's facility applications met all necessary requirements and approved the proposed transmission lines in accordance with Section 17 of the *Alberta Utilities Commission Act.*

Enterprise also filed a connection application. The AUC found that as Enterprise will be the owner and operator of both the substation and the proposed transmission line, a connection order is not necessary. Enterprise would only temporarily be the owner and operator of the proposed transmission line before transferring it to AML. The AUC noted its expectation that an application for a new connection order between the transferred transmission line and the substation be applied for simultaneously with the transmission line transfer application to AML. The applied-for connection order was not granted to Enterprise.

AML's Facility Applications

AML requested approval of alterations to existing facilities to accommodate the connection of the transmission line to the AIES.

The AUC determined that this facility application, filed under sections 14, 15, 18 and 19 of the *Hydro and Electric Energy Act*, comply with the information requirements prescribed in AUC Rule 007, and the proposed development is consistent with the need identified in the AESO's needs application.

The AUC determined that AML's proposed transmission developments are in the public interest, as required by Section 17 of the *Alberta Utilities Commission Act.*

Decision

The AUC approved all applications of this proceeding, except for Enterprise Solar's application for a connection order. As the necessary order for connection between the transmission line and substation will be issued to AML, not Enterprise Solar, the applied-for order was determined to be unnecessary.

***Apex Utilities Inc. Code of Conduct Regulation Compliance Plan Amendments,* AUC Decision 26302-D01-2021**

Code of Conduct Compliance Plan Amendments

In this decision, the Alberta Utilities Commission ("AUC") approved the application of Apex Utilities Inc. ("AUI") to amend its *Code of Conduct Regulation* Compliance Plan ("Compliance Plan").

AUI filed an application with the AUC on February 8, 2021, requesting approval of changes to its Compliance Plan to reflect the changes introduced to the *Compliance Plan Regulation* ("*CCR*") on November 12, 2020. This application was approved on March 24, 2021, in Decision 26302-D01-2021.

On July 12, 2021, the AUC issued a letter advising of its intention to introduce specific provisions within Compliance Plans concerning the AUC's audit oversight and the obligation of parties to retain records for the purposes of that audit. In response,AUI filed a post-disposition submission on September 24, 2021, requesting approval of the further amendments to its Compliance Plan.

In its application, AUI sought approval of changes to sections of the Compliance Plan regarding reporting periods, the list of compliance records and providing the Compliance Plan to affected parties. The AUC was satisfied that the amendments align with Section 40 of the *CCR* and that the changes reflect the repeal of AUC Rule 030. The AUC proposed minor changes in the language of the section regarding the requirement to provide the AUC with a copy of the Compliance Plan once it is approved.

Subject to the minor language change, that AUC approved the application for the amendment of the *CCR* Compliance Plan.

***ATCO Electric Ltd., ENMAX Power Corporation, and FortisAlberta Inc. Decision on Preliminary Question Application for Review of Decision 26061-D01-2021 Commission Related Examination of Distribution Facility Owner Payments Under the Independent System Operator Tariff Customer Contribution Policy,* AUC Decision 26608-D01-2021**

R&V - DFO Contributions - ISO Tariff

In this decision, the Alberta Utilities Commission ("AUC") review panel ("Review Panel") denied the applications from ATCO Electric Ltd. ("AE"), ENMAX Power Corporation ("ENMAX") and FortisAlberta Inc. ("FortisAB") for review and variance of Decision 26061-D01-2021 regarding the AUC's examination of distribution facility owner ("DFO") customer contribution payments under the Independent System Operator ("ISO") tariff.

Background

The issues raised in Proceeding 26061 stem from the AUC's decision regarding the Alberta Electric System Operator's ("AESO") 2018 ISO Tariff (the "2018 Tariff Decision"). In the 2018 Tariff Decision, the AUC approved a proposal from AltaLink Management Ltd. ("AML") to change how the AESO's customer contribution policy is accounted for between a DFO and a transmission facility owner ("TFO").

Because of this approval, the balance of unamortized AESO customer contributions in FortisAB's rate base effective December 31, 2017, was to be sold to AML at net book value. After January 1, 2018, all AESO customer contributions would be capitalized by AML, not FortisAB.

In Decision 24932-D01-2020, the AUC rescinded these findings and the associated approval. The AUC also scheduled a proceeding which would examine: (i) the legal basis of the existing AESO customer contribution policy as it pertains to all TFOs and DFOs; (ii) whether there is a need for a new policy, including consideration of AML's customer contribution proposal; and (iii) if approved, set the prospective date on which any new policy would commence. The proceeding scheduled in Decision 24932-D01-2020 was commenced as Proceeding 26061. The review applicants sought to review and vary the decision issued in Proceeding 26061.

The Commission's authority to review its own decisions is discretionary and is found in Section 10 of the *Alberta Utilities Commission Act*. Rule 016 sets out the process for considering an application for review. The Commission considered the applications under the version of Rule 016 that was applicable when the review applicants filed their applications on June 14, 2021. This review process has two stages. In the first stage, a review panel decides if there are grounds to review the original decision (the preliminary question). If the review panel decides to review the decision, it moves to the second stage where it decides whether to confirm, vary, or rescind the original decision (the variance question). In this decision, the review panel decided the preliminary question.

Grounds for Review

AE submitted that the hearing panel rendered decisions that are:

- inconsistent with the legislative requirements of section 122 of the *Electric Utilities Act* ("*EUA*");

- inconsistent with the judicially recognized regulatory compact that details the rights and obligations of both regulated utilities and their customers; and

- inconsistent with AE's rights, as an applicant, the procedural fairness and due process, in knowing the case it must meet.

ENMAX submitted that by prohibiting electric utilities from earning a fair return on AESO customer contributions or the related transmission facilities, the hearing panel erred in:

- exceeding the limits of the AUC's jurisdiction, thereby failing in its statutory obligation to provide the utilities with a reasonable opportunity to earn a fair return;

- failing to adequately identify or consider the consequences of changing the regulatory accounting treatment of DFO customer contributions, asserting an error in law; and

- breaching its duty of procedural fairness by deciding that neither DFOs nor TFOs will be permitted to earn a return on transmission facilities (or the related customer contributions) that require a customer contribution under the AESO tariff without identifying that as an issue in its notice of application and without giving parties a reasonable opportunity to be heard on that issue.

FortisAB submitted that the hearing panel had erred by making factual findings without sufficient evidence and making factual determinations that are contrary to Section 122 of the *EUA*. FortisAB submitted that the AUC had made this error in its determination to remove the return on equity ("ROE") component earned on any AESO customer contribution payments paid by DFOs.

<u>Review Panel Findings</u>

Treatment of AESO Customer Contributions

(a) Section 122 of the *EUA* and the Opportunity to Earn a Fair Return

The applicants submitted that the hearing panel had made an error in fact, law or jurisdiction as its directions prohibited DFOs from having the opportunity to earn a fair return on AESO customer contributions, contrary to Section 122 of the *EUA*.

The AUC noted that in both the original proceeding and Proceeding 26061, the AESO referenced the AUC's ratemaking discretion. It is within the AUC's authority to determine if a DFO or TFO should earn a rate of return on customer contributions that are paid toward the cost of transmission connection facilities.

Whether AESO customer contributions are a cost and expense associated with a capital investment as described in subsection 122(1)(a), the equity portion of which, in accordance with subsection 122(1)(a)(iv), would attract a fair return, or whether AESO customer contributions are a cost, an expense or an amount that a utility owner is required to pay under other subsections of section 122, is a decision to be made by the AUC applying the law to determine how those contributions should be categorized. The hearing panel expressly did so, provided its reasoning therefor, and concluded that AESO customer contributions are properly an other (non-capital) cost or expense under subsections 122(1)(b) or (h) or an "amount that the owner is required to pay" under subsection 122(1)(c). Because they are not capital investments the hearing panel determined that it was "necessary to (i) remove the profit element (i.e., return-on equity-component) earned on any AESO customer contribution payments DFOs make…".

The hearing panel therefore found that DFOs must not earn a return on the costs incurred for AESO customer contributions. This would avoid the distorted or muted price signals that arise when DFOs can earn a fair return because this converted what was intended to be a price signal, into a revenue signal to DFOs. The review panel determined that these conclusions are consistent with the hearing panel's reliance on subsections 122(1)(b), (c) and (h) of the *EUA* and with its determinations that the AESO customer contributions are properly recoverable in a tariff, but do not provide the owner of the electric utility an opportunity to recover a return on (in addition to the recovery of) these amounts.

AE, ENMAX and FortisAB, as the review applicants, did not demonstrate that the hearing panel exercised its authority in a manner inconsistent with its statutory authority in deciding if the AESO customer contributions should earn a return. Accordingly, the requests to review the hearing panel's direction prohibiting a utility owner from an opportunity to earn a fair return on AESO customer contributions are denied.

(b) The Regulatory Compact

AE argued that the hearing panel's finding that neither a DFO nor a TFO is entitled to a return on AESO customer contributions does not respect the regulatory compact. It was submitted that this constitutes an error of law. FortisAB further argued that the approach adopted by the hearing panel to purportedly correct the price signals directly conflicts with the regulatory compact. The hearing panel had found that the correction would not provide an effective incentive to end-use customers to choose the most economical connection solution.

The review panel found that the hearing panel's findings in the original decision demonstrate that it was aware of the requirement to ensure that a utility is provided with a reasonable opportunity to recover a fair return on the equity portion of capital investments. It noted that the hearing panel underlined that it was removing the ROE component previously earned by DFOs on AESO customer contributions. This would eliminate the incentive that the hearing panel found could exist for a pure-play DFO to prefer a transmission solution over a distribution solution and for a DFO to increase the amount of AESO customer contributions to grow the rate base. The hearing panel stated that it removed the proponent to protect the public interest.

The review panel found that consistent with the regulatory compact, and the hearing panel made its decision while being aware in consideration of shareholder interests, the requirement to ensure that utilities are given a reasonable opportunity to earn an ROE of shareholders, and the interest of ratepayers. The hearing panel's decision that AESO customer contributions were to be treated as an expense was within the panel's discretion and did not constitute a reviewable error of law. Accordingly, the requests to review the original decision on the basis that the hearing panel erred in law in deciding inconsistent with the regulatory compact are denied.

Jurisdiction

AE and ENMAX stated that the hearing panel had exceeded its jurisdiction. In the original decision, the hearing panel decided that the DFO tariff recovery mechanism applicable to AESO customer contributions in effect at the time did not provide effective price signals to provide end-use customers with an incentive to choose the most economical connections solution. It was also concluded that the intended price signal is likely absent because the DFO can earn a return on AESO customer contributions payments.

The AUC was not persuaded that the original decision is inconsistent with the doctrine of implied authority, as argued by ENMAX. It found that the objectives pursued in the original decision are consistent with the AUC's rate-setting mandate to safeguard the public interest in the nature and quality of the service to the widest proportions.

The AUC noted that the future accounting treatment of AESO customer contributions is simultaneously being considered in Proceeding 26521. The AUC noted that accounting treatment for AESO customer contributions for the DFOs was not known at the time of this decision, as their treatment was still being considered in Proceeding 26521.

The hearing panel supported the principles it had previously found to be the foundation for a customer contribution policy, most importantly establishing an effective price signal for the siting of connection facilities. The review panel found that the hearing panel had correctly exercised its discretion in determining if an incentive is not in the public interest. The hearing panel did not make any error in its conclusion on how to properly give effect to the principle of sending effective price signals.

The AUC found that no error of jurisdiction was shown to be apparent on the face of the decision or otherwise exists on a balance of probabilities warranting a review, variance or rescission of the decision.

Sufficiency of Evidence

ENMAX and FortisAB argued that the hearing panel's finding that the DFO tariff recovery mechanism applicable to AESO customer contributions, in effect at the time of the original decision, does not provide effective price signals encouraging the choice of the most economical connection solution by end-use customers was not supported by enough evidence.

The review panel determined that wording chosen by the hearing panel in the previous decision demonstrated that its considerations were general in nature and related to the AESO customer contribution scheme as it pertains to DFOs in general. The hearing panel did not make any findings specifically related to FortisAB. The review panel determined that the hearing panel was aware of previous decisions, including those raised by FortisAB, in its argument regarding a lack of evidence. The hearing panel made its decision notwithstanding and without varying findings of the 2018 AESO tariff decision.

The AUC found that FortisAB and ENMAX did not demonstrate an error of fact, law or jurisdiction that could lead the AUC to materially vary or rescind the decision.

Procedural Fairness

The applicants questioned whether, through the process established in the proceeding of the original decision, the applicants were provided with reasonable notice of the issues to be addressed by the hearing panel and raised by the interveners and with an opportunity to address these issues.

The review panel found that, based on the comprehensive notice issued for the original proceeding, registered parties, including AE and ENMAX, knew, or reasonably should have known, the scope of the original proceeding.

The hearing panel was explicitly considering the legal basis of the AESO customer contribution policy as it pertains to all TFOs and DFOs and whether a new AESO customer contribution policy was needed. The hearing panel was permitted to render a decision on not only the identified issues but also other issues which arose from the submissions received, was free to accept or reject evidence presented by the parties, and was entitled to use its expertise to arrive at different conclusions than the parties.

The AUC found that the review applicants did not demonstrate an error on the grounds of procedural fairness to the extent that it could lead the AUC to materially vary or rescind the original decision. The review applicants' requests for review on the grounds of a lack of procedural fairness was therefore denied.

***ATCO Electric Ltd. Stage 2 Review and Variance of 2018-2019 General Tariff Application Compliance,* AUC Decision 26519-D01-2021**

R&V - Revenue Requirements

In this decision, the Alberta Utilities Commission ("AUC") considered whether ATCO Electric Ltd. ("AE"), ATCO Transmission and ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. (the "ATCO Utilities"), complied with the direction issued in Decision 25938-D01-2021.

In Decision 25938-D01-2021, the AUC reviewed and varied a direction issued in Decision 24805-D02-2020 requiring AE to include the equity portion of the allowance for funds used during construction ("AFUDC") as part of the total utility earnings before tax, but not the debt portion, among other things.

The amended direction affects the calculation of AE's regulatory income tax expense in its 2017 to 2022 revenue requirements. After the release of Decision 25938-D01-2021, and to be consistent with the amended direction, AE revised the calculation of its regulatory income tax expense in its applied-for 2020 to 2022 revenue requirements. ATCO Pipelines also revised the same calculation for its applied for 2021 to 2023 revenue requirements.

Issues

To comply with the amended direction, the accounting of AFUDC in the calculation of income tax expense, for regulatory purposes, required the ATCO Utilities to include the equity portion of AFUDC as part of the total utility earnings before tax, excluding the debt portion. The accounting then requires a deduction for the equity portion, which results in no net deduction for the equity component of AFUDC being reflected in the regulatory income tax expense. The accounting also requires a deduction for the debt component, which reduces revenue requirements.

The AUC noted that the Stage 1 review decision and this decision affect the calculation of income tax expense in several ways. These decisions also affect ATCO Pipelines' 2021 to 2023 general rate application ("GRA"). On April 13, 2021, ATCO Pipelines revised its compliance application in Proceeding 26443, proposing an adjustment to its treatment of AFUDC for calculating its regulatory income tax expense to comply with the amended direction. It submitted that this proposed adjustment decreased its 2021, 2022 and 2023 revenue requirements by $380,000, $257,000 and $148,000, respectively.

In this proceeding, the AUC considered the potential impacts to the revenue requirement calculations and any other corresponding adjustment along with AE's treatment of AFUDC.

Has AE Updated the Placeholder Amount, Approved in Decision 26247-D01-2021, Disposing of Its 2015-2017 Transmission Deferral Accounts Application to Comply with the Amended Direction?

In Decision 26247-D01-2021, the AUC determined that AE had complied with Direction 14 from Decision 24375-D01-2020. AE calculated and included the refund for the difference in 2017 AFUDC tax inputs between the forecast and actual costs. ATCO Electric had also proposed a second calculation based on the method proposed in proceeding 25938. Proceeding 25938 was still in progress at the time of Decision 26247-D01-2021.

In response to the amended direction, AE provided an amended 2017 AFUDC refund amount of $2.19 million in the current Stage 2 review and variance application, which was approved by the AUC. To adjust for the approved amended 2017 AFUDC refund, the AUC ordered ATCO Electric to settle the placeholder adjustment of $800,000 through a one-time billing to the Alberta Electric System Operator ("AESO") by October 30, 2021

Has AE Amended the Calculation of its Regulatory Income Tax Expense, for its 2018 and 2019 GTA, to Comply with the Amended Direction?

AE was directed to remove the equity and debt portions of AFUDC from the utility earnings before tax in its calculation of income tax expense. In this proceeding, in response to the amended direction, AE added the equity portion of AFUDC to the utility earning before tax and deducted both the equity and the debt portions of AFUDC in the calculation of its income tax expense. The effect of adding the equity portion of AFUDC to the utility's income before tax results in a revenue requirement increase of $2.4 million in 2018 and $2.2 million in 2019.

The AUC determined that ATCO Electric's final approved revenue requirement should be $678.8 million in 2018 and $681.6 million in 2019.

Do the Placeholder Amounts from ATCO Pipelines' Compliance Filing and the 2020-2022 GTA Compliance Filing Schedules Comply with the Amended Direction?

The AUC determined that the 2020-2022 GTA compliance filing schedules were adjusted as required to adjust for the change in revenue requirement. Further, ATCO Pipelines' treatment of AFUDC, for the purposes of calculating its income tax expense, is consistent with the amended direction.

Other Matters

In AE's next GTA, the AUC will consider if the collection of future income tax should continue and if AE should be permitted to continue to treat the equity portion of AFUDC as a temporary rather than a permanent tax difference in the calculation of its tax expense.

Order

AE was ordered to settle $800,000 through a one-time billing to the AESO by October 30, 2021. The AUC approved ATCO Electric's revenue requirements for 2018 and 2019 as $678,800,000 and $681,600,00, respectively.

***ATCO Pipelines, a Division of ATCO Gas and Pipelines Ltd. Decision on Preliminary Question Application for Review of Decision 26443-D01-2021 2021-2023 General Rate Application Compliance Filing*, AUC Decision 26719-D01-2021**

R&V - Rates

In this decision, the Alberta Utilities Commission ("AUC") denied an application by ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. ("ATCO Pipelines"), to review and vary Decision 26443-D01-2021 for the utility's 2021-2023 general rate application ("GRA") compliance filing (the "Compliance Decision").

Background

In the Compliance Decision, the AUC addressed ATCO Pipeline's compliance filing arising from directions issued in Decision 25663-D01-2021 (the "GRA Decision"), which addressed ATCO Pipeline's revenue requirements to provide natural gas transmission service for 2021, 2022 and 2023.

In the GRA Decision, the AUC was concerned by a pattern of conservative forecasting of operating costs by ATCO Pipelines and determined that a top-down adjustment to the forecast operating costs was warranted. As part of the GRA Decision, the AUC issued Direction 10, which required a five per cent overall reduction to forecast operating costs in each of 2021, 2022 and 2023.

Further, the AUC in the GRA Decision found that reductions were required to specific operating costs. To avoid the effects of double-counting the top-down adjustment and these specific adjustments, the AUC issued Direction 11 requiring a specific calculation method.

In the Compliance Decision, the AUC was not satisfied that ATCO Pipelines had fully complied with the directions. Specifically, the AUC was not satisfied that Direction 11 was complied with as ATCO Pipelines had not removed all categories of operating costs subject to the specific adjustments before applying the top-down adjustment. The AUC determined that this resulted in a double-counting which was supposed to be avoided through Direction 11.

Based on the determinations that ATCO Pipelines improperly excluded the operating cost categories total labour costs and IT operating costs from the five per cent top-down adjustment to operating costs, the compliance panel further reduced ATCO Pipelines' revenue requirements by $1.517 million in 2021, $1.555 million in 2022 and $1.577 million in 2023.

Issues

Was There an Error of Fact, or Mixed Fact and Law, in the Compliance Panel's Determinations Related to Directions 10 and 11 in Respect of ATCO Pipelines' Total Labour Costs and IT Costs?

(a) Directions 10 and 11 and Total Labour and IT Costs

In its review application, with respect to both total labour costs and IT operating costs, ATCO Pipelines argued that the compliance panel's determinations regarding these costs ignore the plain wording of Direction 10 and Direction 11.

ATCO Pipelines argued that because IT operating costs had been approved in the GRA Decision, the compliance panel erred in concluding that these costs should not have been removed from the top-down adjustment. It argued that the compliance panel's findings effectively changed Direction 11 to require that ATCO Pipelines apply a five per cent reduction to its approved IT operating costs.

The AUC panel in this review proceeding noted that, for both total labour costs and IT operating costs, ATCO Pipelines disagreed with the compliance panel's interpretation of the two directions. However, the AUC determined that ATCO Pipelines did not demonstrate that the assessment and findings in the Compliance Decision were inconsistent with the intent of the two directions. The review panel found that there was no error in the approach taken by the compliance panel.

(b) Double-Counting of Total Labour Costs and IT Costs

ATCO Pipelines submitted that double-counting occurred because of the compliance panel's findings with respect to both total labour costs and IT operating costs.

The review panel found that ATCO Pipelines did not provide support for the assertion that the compliance panel's calculation, which was to remove the revenue requirement impacts of directions 12, 13 and 14 before applying the five per cent top-down adjustment, results in double-counting. Without support in the review application to demonstrate that the compliance panel made an error of fact or mixed fact and law, ATCO Pipelines' arguments for a review fail to meet the test established in Rule 016.

The review panel found that ATCO Pipelines did not demonstrate that the hearing panel had erred in its findings in applying directions 10 and 11 to ATCO Pipelines' total labour costs and IT operating costs, or with respect to double-counting. The request for review on these issues was denied.

Was There an Error of Fact in the Compliance Panel's Determinations Related to Directions 10 and 11, in Respect of the Total Amount of the Reductions to ATCO Pipelines' Forecast Operating Costs?

ATCO Pipelines argued that because the top-down adjustment would apply to a lower level of forecast operating costs, it could reasonably be expected that the level of top-down adjustment would also be lower. It concluded that the resulting reductions represent an error of fact regarding the level of adjustment to its forecast operating costs.

The review panel was not persuaded. It found that the GRA Decision did not suggest that ATCO Pipelines' forecasted operating costs could not be reduced in a way adopted by the compliance panel. Specifically, it found no language suggesting that the total reductions contemplated should not exceed the five per cent top-down adjustment. The AUC found no error of fact in this regard in the compliance panel's determinations.

Decision

The request for a review of the resulting reductions to ATCO Pipelines' total labour costs and IT operating costs used in deriving ATCO Pipelines' forecast operating costs was denied.

***Conifer Energy Inc. Judy Creek 16-Megawatt Power Plant,* AUC Decision 26647-D01-2021**
Facilities - Natural Gas

In this decision, the Alberta Utilities Commission ("AUC") approved the application from Conifer Energy Inc. ("Conifer") to construct, operate and connect a 16-megawatt ("MW") natural gas power plant, designated as the Judy Creek 16-MW Power Plant (the "Power Plant").

Application

Conifer filed an application with the AUC requesting approval to construct and operate the Power Plant and connect it to ATCO Electric's electric distribution system (the "Project"). The Project will be located near Swan Hills in Big Lakes County.

The Power Plant includes three low emission, low noise natural gas-driven generating units for a combined total maximum capability of 16 MW.

AUC Findings

The application included a participant involvement program, noise impact assessment, air quality assessment report and correspondences with ATCO Electric Ltd., confirming that the Power Plant can be interconnected.

The AUC determined that the application complied with the requirements Rule 012: *Noise Control* and Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments.* At the time of this proceeding, an *Environmental Protection and Enhancement Act* application was still being considered by Alberta Environment and Parks. The AUC considered that it was unlikely that this would raise any issues.

The application was found to be in the public interest, as required by Section 17 of the *Alberta Utilities Commission Act.* Accordingly, and pursuant to Section 11 and Section 18 of the *Hydro Electric and Energy Act,* the AUC approved the applications to construct, operate and interconnect the Power Plant.

***Direct Energy Regulated Services Application to Recover Undercharged Distribution Line Loss Factor Amounts,* AUC Decision 26654-D01-2021**
Price Setting Plan

In this decision, the Alberta Utilities Commission (“AUC”) denied the application by Direct Energy Regulated Services (“DERS”) to recover $318,968 from its regulated rate option (“RRO”) customers for amounts DERS deemed were undercharged between August 2020 and April 2021 for distribution line loss factors (“DLLFs”). These amounts were included as part of the calculation of the monthly energy charges in accordance with DERS’ approved energy price setting plan (“EPSP”) approved in Decision 24296-D01-2019 and Decision 24296-D02-2020.

Application Details

DERS submitted its application citing Section 17 of the *Regulated Rate Option Regulation* as the legislation authorizing the recovery of the undercharged DLLFs. Section 17 sets out that an RRO provider can collect specific unrecovered amounts that have been incurred in the 12 months preceding the date of the bill in which they are being recovered. DERS explained that the undercharges were a result of an unforeseen forecasting error. This forecasting error was a result of a change to the distribution tariff of ATCO Electric Ltd. (“AE”) without a corresponding update to AE’s distribution line loss factor.

In Decision 24747-D01-2021, the AUC approved the elimination of Option H(b) from AE’s distribution price schedules. DERS submitted that this affected how AE calculates and allocates its distribution line losses to retailers. Despite this change and the resulting rise in actual DLLFs allocated to DERS by AE, the approved distribution line losses by rate class for the AE distribution services area have not changed. DERS used the unchanged distribution line losses to calculate monthly energy charges for August 2020 to April 2021. This resulted in an undercharge to its RRO customers.

Issues

The AUC determined that the primary issue of the application was if the amount described by DERS qualify as an undercharge that can be recovered from RRO customers pursuant to Section 17 of the *Regulated Rate Option Regulation*.

The AUC determined that this was not the case. It determined that DERS did not make any errors on its customer’s bills. Further, DERS is compensated for any forecast errors related to DLLFs through the risk margin it receives.

Does the Use of Forecast Line Losses in Accordance with the Approved EPSP Result in an Undercharge?

The AUC determined that the use of forecast DLLF percentages as approved in the EPSP do not result in an incorrect rate calculation or other error of any kind if the actual DLLF percentages are higher than the forecast. Accordingly, there is no error constituting an undercharge pursuant to Section 17 of the *Regulated Rate Option Regulation*.

When calculating the monthly RRO energy charges for the period in question, the forecast DLLF percentages included as inputs to those calculated energy charges were derived in accordance with the EPSP. DERS' forecast DLLF percentages for each rate class were the same for every month and were calculated using the most recently approved distribution line losses by rate class for AE's distribution service area. As a result, the DLLF percentages were calculated in accordance with the approved EPSP, and consequently, there was no error in energy charges.

Section 17 should be interpreted to relate to errors associated with customers' bills and not differences between forecast and actual distribution line losses.

Is Section 5(3)(d) of the Regulated Rate Option Regulation Relevant?

DERS argued that Section 5 of the *Regulated Rate Option Regulation* is not relevant to its application because the risk recovered by the risk margin does not include the type of risk that materialized. It stated that the risk that materialized was a regulatory decision that ensured that DERS' forecast methodology would be incapable of achieving its intended purpose.

Following a plain read of section 5 and considering the provisions of the *Regulated Rate Option Regulation*, the AUC determined that the risk of distribution line losses is to be included in the risk margin of DERS as part of its regulated rate tariff. DERS, as the RRO provider, bears the risk associated with differences between forecast and actual distribution line losses allocated to it. Consequently, DERS also receives compensation for this risk through the risk margin. It is a risk DERS is exposed to in providing RRO service, and DERS' exposure to that risk was contemplated by the legislature in section 5(3)(d) of the *Regulated Rate Option Regulation*.

The AUC determined that the forecast risk can be considered as part of DERS' risk compensation under Section 5 of the *Regulated Rate Option Regulation*. The AUC, therefore, found that the approval of the application would be inconsistent with section 5(3)(d) and section 5(5) of the *Regulated Rate Option Regulation*.

Is Section 3(2) of the Regulated Rate Option Regulation Relevant?

The AUC found that DERS' application does not qualify under Section 17 of the *Regulated Rate Option Regulation*. Section 3(2) is relevant, and the application would be in violation of section 3(2) because it amounts to a true-up. The AUC stated that the nature of RRO energy charges is that they are set in advance and considered to be final when they are acknowledged by the AUC. Accordingly, the RRO providers are not permitted to adjust these charges after the fact. The purpose of sections 3(2) and 6(2) are for true-ups, rate riders or similar accounts or devices. The risk for distribution line losses was contemplated to be included in the risk margin of DERS as part of its regulated rate tariff, and therefore these losses are prohibited from true-up in sections 3(2) and 6(2) of the *Regulated Rate Option Regulation*.

To What Extent Should an RRO Provider Bear the Responsibility for Monitoring Items Included in the EPSP?

The AUC found that the RRO provider is required to monitor items included in the EPSP to ensure that the forecasting method remains relevant. This includes the responsibility to monitor distribution line losses.

The AUC further found that there was no requirement that DERS determined that the forecast error is permanent before making an application to the AUC to change the DLLF percentage forecast method. DERS could have applied to change the DLLF percentage forecast method at any time to mitigate its forecast risk. The decision to wait and determine if the forecasting error is permanent supports that the change to the DLLF percentage was a component of DERS' forecast risk that remained with DERS as an owner under the *Regulated Rate Option Regulation.*

Decision

The AUC denied the application of DERS to recover $318,968 from its RRO customers for amounts deemed to be undercharged between August 2020 and April 2021 for distribution line loss factors.

***EPCOR Energy Alberta GP Inc. 2021-2024 Energy Price Setting Plan,* AUC Decision 26316-D02-2021**

Regulated Rate Option - Price Setting Plan

In this decision, the Alberta Utilities Commission ("AUC") determined that EPCOR Energy Alberta GP Inc. ("EPCOR") has complied with directions issued in AUC Decision 26316-D01-2021. The AUC also approved energy procurement under the 2021-2024 energy price setting plan ("EPSP") starting in January 2022. The first month that regulated rate option ("RRO") energy charges will be determined in accordance with the 2021-2024 EPSP is May 2022, conditional on an executed backstop agreement being before March 1, 2022.

Compliance with Directions from Decision 26316-D01-2021 and a Minor Correction to the 2021-2024 EPSP

In Decision 26316-D01-2021, the AUC required that EPCOR makes specific amendments to the 2021-2024 EPSP and illustrative energy charge model and to file the amended documents for approval.

The subject of this Decision 26316-D02-2021 were the directions issued by the AUC that focus on updating and filing a revised 2021-2024 EPSP and filing a stand-alone load forecasting method and revised illustrative energy charge model.

The AUC directed EPCOR to update the date range of the EPSP and include the first month and last month for which the electric energy charges will be calculated under the EPSP. EPCOR argued that the first month for which the electric energy charges will be calculated under the EPSP depends upon when the backstop agreement for the EPSP is in place. However, the AUC found that EPCOR had complied with this direction in the updated EPSP.

Further directions required EPCOR to make specific revisions to the load forecasting method, to remove it and the accompanying usage forecasting illustrative model from the 2021-2024 EPSP, and to file a stand-alone load forecasting method. The AUC was satisfied that these directions were complied with.

The AUC was also satisfied that EPCOR had made the directed changes to the illustrative energy charge model.

Approvals and Direction

As the directions were complied with, the AUC approved the 2021-2024 EPSP and attachments discussed in this decision. The AUC approved May 2022 as the first month in which energy charges will be determined in accordance with the EPSP. EPCOR is directed to file the executed backstop agreement no later than March 1, 2022, 60 days before May 1, 2022.

***EPCOR Energy Alberta GP Inc. 2021 Revised and 2022 Interim Regulated Rate Tariff Application,* AUC Decision 26891-D01-2021**

Revised Rates Maintained

In this decision, the Alberta Utilities Commission ("AUC") approved the application for approval of the revised 2021 interim non-energy rates and 2022 interim non-energy rates from EPCOR Energy Alberta GP Inc. ("EPCOR").

Details of the Application

In this application, EPCOR requested approval of the following:

- non-energy charges for EPCOR Distribution and Transmission Inc. ("EDTI") and FortisAlberta Inc. ("FortisAB") service areas;
- EDTI service area and FortisAB service area: Price Schedules and Miscellaneous Fees Price schedules, including Miscellaneous Fees;
- EPCOR's regulated rate tariff ("RRT") terms and conditions; and
- a hearing cost reserve account and short-term incentive deferral account on an interim refundable basis as applied for in its 2021-2022 RRT application.

EPCOR submitted that the differences between the current interim rates and forecast non-energy rates are considerable. EPCOR requested approval to increase or decrease rates by half the difference between 2021 approved interim rates and 2021 forecast rates for each customer class. It also requested that those rates stay effective until the AUC approves a final RRT for 2021 and 2022 or a revised interim RRT.

Revising Interim Rates and Possible Rate Shock

The AUC found it reasonable and efficient to maintain the revised 2021 interim rates into 2022, as suggested by EPCOR.

The revised rates resulted in significant increases for the FortisAB Irrigation (41.27 per cent) and Farm (14.10 per cent) customer classes and EDTI Lighting (14.06 per cent) lighting class. The AUC determined that issues such as rate shock for these customer classes could be addressed in EPCOR's 2021-2022 non-energy RRT application, which was also before the AUC at the time of this proceeding. While the increases are significant, approving the revised interim rates and carrying them into 2022 would ease any potential rate impact on these customers when compared to EPCOR's current interim rates.

The AUC considered EPCOR's request for a revision to its 2021 RRT interim rates and proposed 2022 RRT interim rates to be justified. The AUC approved the revised interim 2021 rates and 2022 interim rates as requested by EPCOR on a refundable basis.

***Gleichen Solar Project Inc., Gleichen Solar Project,* AUC Decision 26767-D01-2021**

Facilities - Solar

In this decision, the Alberta Utilities Commission ("AUC") approved the application from Gleichen Solar Project Inc. ("Gleichen") to construct and operate a 13.3-megawatt solar power plant, designated as the Gleichen Solar Project (the "Power Plant"), and to connect the Power Plant to the FortisAlberta Inc. electric distribution system.

Application

The Power Plant will consist of photovoltaic modules and seven inverter or transformer stations with an installed capability of 13.3 megawatts ("MW") and will be located on 71 acres of private, freehold land near Gleichen in Wheatland County.

The application included a participant involvement program detailing consultation and notification of stakeholders. It also included a renewable energy project submission filed with Alberta Environment and Parks ("AEP"), an AEP renewable energy referral report, an environmental evaluation, a conceptual conservation and reclamation plan, a solar glare assessment and a noise impact assessment. Further, Gleichen submitted a *Historical Resources Act* approval, a site-specific emergency report plan for the project's construction and operation and confirmation that FortisAlberta Inc. is prepared to interconnect the Power Plant to its distribution system.

AUC Discussion and Findings

The AUC determined that the project met all requirements for a connection order and was satisfied by FortisAlberta Inc.'s confirmation to allow the interconnection.

The AUC determined that the application and the information submitted meet the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and Rule 012: *Noise Control.* The reports and information submitted with the application did not raise any concerns.

In accordance with Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*, the AUC required as a condition of approval that Gleichen submits an annual post-construction monitoring survey report to AEP and the AUC within 13 months of the project becoming operational, and on or before the same date every following year for which AEP requires surveys according to subsection 3(3) of Rule 033.

The solar glare assessment indicated that the solar panels would be mounted on a racking system with a fixed-tilt angle of 30 degrees and assumed that the project solar panels would use an anti-reflective coating. To ensure that the project does not create hazardous glare conditions for nearby dwellings or transportation routes as indicated in the glare assessment, the AUC required as a condition of approval that Gleichen shall use an anti-reflective coating on the project solar panels.

Further, regarding glare, the AUC imposed as a condition of approval that Gleichen shall file a report with the AUC detailing any complaints or concerns it receives or is made aware of regarding solar glare from the project during the first year of operation. The report must also include the response to the complaints or concerns no later than 13 months after the project becomes operational.

The noise impact assessment predicted compliance with Rule 012: *Noise Control*. The AUC found it reasonable to implement the recommended acoustic sound barriers at one receptor if required following a post-construction sound level survey. Accordingly, to ensure the project remains compliant with Rule 012, the AUC imposed as a condition of approval that Gleichen conducts a post-construction comprehensive sound level ("CSL") survey at Receptor R03. Gleichen shall file a report summarizing the results of the CSL survey no later than 60 days after the project commences operations. If the post-construction CSL survey demonstrates that the project is not compliant with Rule 012 at Receptor R03, Gleichen shall immediately cease nighttime operation until noise barriers or other mitigation measures are enough to achieve compliance with Rule 012. In this case, Gleichen shall conduct another CSL survey and file a report with the AUC.

Finally, the AUC required that Gleichen files a final project update to the AUC to confirm that the project has stayed within the final project update specified allowances for solar power plants once it has finalized its equipment selection and project layout.

AUC Decision

The AUC found approval of the application to be in the public interest, as required by Section 17 of *the Alberta Utilities Commission Act*. Pursuant to sections 11 and 18 of the *Hydro and Electric Energy Act*, the AUC approved the applications for permission to construct and operate the Power Plant and interconnect to FortisAlberta Inc.'s electric distribution system.

***Irrigation Canal Power Co-operative Ltd. Fincastle Solar Project,* AUC Decision 26861-D01-2021**

Facilities - Solar

In this decision, the Alberta Utilities Commission ("AUC") approved the application from Irrigation Canal Power Co-operative Ltd. ("IRRICAN") to qualify the 938-kilowatt ("kW") Fincastle Solar Project (the "Project") as a community generating unit.

Application

In this application, Elemental Energy Inc., on behalf of IRRICAN, only requested the qualification of the Project as a community generating unit under the *Small Scale Generating Unit Regulation.* It did not apply for permission to construct or operate the underlying Project.

Construction of the Project with a final output capacity of 938 kW near the town of Taber is scheduled to start in the spring of 2022. FortisAlberta Inc. confirmed that it would be responsible for the metering costs of the Project if the application is approved.

IRRICAN provided a community benefits statement describing the economic, environmental, and social benefits the Project would bring the districts in the area. It indicated the Project would generate approximately $3,625,000 in revenue over its 25-year lifespan, as well as $7,900 in annual property tax revenues for the Municipal District of Taber. The Project would be located on an orphan well surface lease, thereby repurposing unused land.

IRRICAN stated that the Project would comply with the small power plant exemption stipulated in section 18.1 of the *Hydro and Electric Energy Regulation* and with Rule 012: *Noise Control.*

AUC Findings

Considering the size of the Project, the AUC accepted that the Project is a small power plant within the meaning of subsection 18.1(1) of the *Hydro and Electric Energy Regulation*. The AUC was also satisfied that the requirements of Rule 012 had been met and, accordingly, determined that the Project is not subject to sections 11 and 18 of the *Hydro and Electric Energy Act.*

The AUC was satisfied that the application satisfied the requirements of the *Small Scale Generation Regulation.* Pursuant to subsection 5(2)(a) of the *Small Scale Generation Regulation*, the distribution owner, FortisAlberta Inc., is entitled to recover the costs incurred to purchase the meter for the Project. To ensure compliance with subsection 5(2)(a), the AUC imposed as a condition of approval that IRRICAN must provide the AUC with written confirmation of the actual cost to purchase the meter once the distribution owner has purchased the meter for the community generating unit.

Decision

Pursuant to Section 3 of the *Small Scale Generation Regulation*, the Fincastle Solar Project was designated as a community generating unit.

Kalina Distributed Power Limited Kalina Energy Centre – Saddle Hills, **AUC Decision 26744-D01-2021**
Power Plant - Interconnection

In this decision, the Alberta Utilities Commission ("AUC") approved the application from Kalina Distributed Power Limited ("Kalina") to construct and operate a power plant designated as the Kalina Energy Centre – Saddle Hills (the "Power Plant") and to connect the Power Plant to ATCO Electric Ltd.'s distribution system.

Application

The Power Plant is a combined cycle power generation facility with two 22.5-megawatt ("MW") gas-fired turbines, two heat recovery vapour generators, two 10.4-MW vapour turbine generators, a 0.4-MW emergency backup generator and other associated equipment. The net generating capability will be approximately 64 MW as two MW will be consumed internally.

Kalina's application included a participant involvement program ("PIP") confirming that there are no outstanding concerns from impacted parties. It also included an environmental evaluation indicating that the project would have a limited environmental impact. It further included air dispersion modeling and a noise impact assessment ("NIA") that indicated compliance with all applicable rules, as well as a confirmation of the *Historical Resources Act* approval and that ATCO Electric Ltd. does not object to the interconnection.

AUC Findings

The AUC found that the application met the information requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. The AUC was also satisfied that the submitted PIP confirmed that Kalina had consulted with all affected parties and complied with Rule 007. Further, the NIA confirmed that the Power Plant is compliant with Rule 012: *Noise Control*.

Based on the proposed Power Plant activities, implementation of environmental mitigation measures, and the residual effects to the ecosystem components assessed, the AUC accepted the conclusion of the environmental evaluation, confirming that the Power Plant would have a limited environmental impact.

The AUC noted that ATCO Electric Ltd. did not object to the interconnection of the Power Plant subject to its technical feasibility, to Kalina's execution of a final interconnection proposal, or Kalina meeting ATCO Electric Ltd.'s interconnection requirements and the terms and conditions for connection of distributed generation.

Accordingly, the AUC found approval of the application to be in the public interest, as required by Section 17 of the *Alberta Utilities Commission Act*. Pursuant to sections 11 and 18 of the *Hydro and Electric Energy Act*, the AUC approved the applications for permission to construct and operate the Power Plant and interconnect to ATCO Electric Ltd.'s distribution system.

Revised Regulatory Accounting Treatment for Alberta Electric System Operator Customer Contributions, **AUC Decision 26521-D01-2021**

Return – 2023 COS Rebasing Application

The Alberta Utilities Commission ("AUC") determined that the revised accounting treatment for Alberta Electric System Operator ("AESO") customer contributions will require each distribution facility owner ("DFO") to expense the contributions in the year that they occur through use of the Y factor mechanism under performance-based regulation ("PBR"). This treatment will be applied during the 2023 cost-of-service ("COS") rebasing and any following PBR term. The AUC further approved the establishment of a deferral account for AESO customer contributions if the amounts in a particular year are large enough to contribute to rate shock.

The AUC noted that it expects that carrying costs on the AESO customer contribution amounts included in the Y factor will be calculated using Rule 023: *Rules Respecting Payment of Interest*. If a longer-term deferral account is needed, the AUC would determine the carrying costs and amortization period on an individual basis based on the proposals from DFOs.

Background and Procedural Summary

This Proceeding 26521 was initiated following Decision 26061-D01-2021. In Decision 26061, the AUC found that the DFO tariff recovery mechanism applicable to AESO customer contributions in effect at the time did not provide a price signal that effectively incents end-use customers to choose the most economical connection solution. Accordingly, the AUC decided that DFOs would no longer be able to earn a return on AESO customer contribution payments and that the customer contributions are to be flowed through to the DFO customer requesting a new connection. The AUC directed DFOs to file proposals for revised regulatory accounting treatment for future customer contributions. This decision considers the intended revised regulatory accounting treatment.

Issues and AUC Findings

Types of AESO Contributions

Participating DFOs, specifically ATCO Electric Ltd. ("AE"), highlighted two contribution scenarios that must be considered when assessing if the current accounting policy meets the objective of the AUC's directions in Decision

26061-D01-2021. First, there are customer to distribution to transmission contributions ("C to D to T contributions") that can be assigned to a specific customer. Second, there are distribution to transmission contributions ("D to T contributions") that cannot be assigned to a customer and are for system upgrades to serve multiple customers, required under the DFO's obligation to serve.

Regarding the first scenario, AE noted that its accounting process complies with the AUC's directions as an identifiable customer pays the contribution. The DFO does not include the contribution in its rate base. Accordingly, and as the DFO would not record any investment related to the upgrades on the transmission system, no adjustment to the accounting mechanism is needed. The AUC agreed with AE's explanation and conclusion regarding the C to D to T contributions. It found that such a DFO is not earning a return in this scenario and that the mechanism complies with its directions.

Regarding the D to T contributions, AE explained that the accounting practice in place is appropriate because the request for a transmission facility is for a group of customers that cannot be identified. In this case, the utility must invest to fulfill its obligation to serve. In return, the utility is given the opportunity to earn a fair return on the investment. AE and ENMAX Power Corp. argued that the revised accounting treatment should not apply to these projects as they cannot be attributed to a specific individual or group of customers. If the revised treatment must apply to these contributions, the contributions should be flowed through to all distribution customers.

Regarding the D to T contributions, the AUC was concerned that because of the incentives created under the previous DFO tariff recovery mechanism applicable to AESO customer contributions, the contributions were generally not being flowed through to the customers that trigger the need for new connection assets, even where such customers could be identified. Instead, the AUC found that these contributions were being distributed across all DFO customers and treated as D to T contributions on which DFOs earned a return. The AUC therefore found that, for D to T contributions, the accounting treatment must change to ensure compliance with AUC directions.

Revised Regulatory Accounting Treatment

The DFOs preferred to treat the AESO customer contributions as an expense item in the year in which they occurred. Using the Y factor mechanism under PBR, the contributions could be flowed through to the customers. The DFOs proposed that the annual Y factor amount would be based on a forecast of the AESO customer contributions. This would be subject to true-up in a subsequent annual rate filing, with the application of carrying charges.

The AUC agreed with DFOs that expensing the AESO customer contributions in the year in which they occur is consistent with its directions from Decision 26061-D01-2021 to remove the equity component earned by the DFOs on the contributions. The AUC determined that a proposal from FortisAlberta Inc. ("FortisAB") to achieve compliance by using the Y factor under PBR with an equivalent treatment applied during the 2023 COS rebasing and all subsequent PBR terms is reasonable and would support rate stability. The proposal to submit an annual forecast for the AESO contribution Y factor amounts subject to a true-up in a subsequent annual rate filing was approved.

The AUC found that it may be necessary to establish a deferral account that is amortized over a longer period in the event that expensing AESO customer contributions in the year they occur will cause rate shock. The AUC further found that the amortization period should be as short as possible and that the deferral account should only be used to reduce the impact of rate shock.

The AUC noted its expectation that DFOs will propose carrying costs calculated using Rule 023 on any deferral account balances.

The amortization period and any proposed carrying costs will be determined on a case-by-case basis that takes into account a DFO's unique circumstances.

Implementation

Because of its findings from Decision 26061-D01-2021 and the decision to implement the revised DFO tariff recovery mechanism on a prospective basis as of April 23, 2021, the AUC directed each DFO to include in its 2023 COS rebasing application any forecast of AESO customer contributions for 2023 to be accounted for as expenses. This now needs to include any deferral account proposal as approved in this Decision 26521-D01-2021, including proposed carrying costs and amortization period if the AESO customer contributions are forecast to contribute to rate shock. The opening 2023 forecast rate base may not include any AESO customer contributions made after April 23, 2021, as they are treated as expense amounts as determined in this decision.

***Sage Water Services Corp. 2020-2023 General Rate Application,* AUC Decision 24695-D01-2021**
Rates – GRA

In this decision, the Alberta Utilities Commission ("AUC") considered the general rate application ("GRA") filed by Sage Water Services Corp. ("Sage Water"), requesting the establishment of final water rates until March 31, 2023.

Sage Water applied for revenue requirements of $184,900 from November 19, 2020, to March 31, 2021; $462,000 from April 1, 2021, to March 31, 2022; and $473,900 from April 1, 2022, to March 31, 2023 (the "test periods").

The AUC determined that downward adjustments of several applied-for amounts were necessary and approved lower revenue requirements for the test periods. The AUC approved revenue requirements of $156,735 for November 19, 2020, to March 31, 2021; $404,005 for April 1, 2021 to March 31, 2022; and $412,366 for April 1, 2022, to March 31, 2023.

The AUC ordered that Sage Water is to resume the use of a fixed monthly rate structure and allocated the revenue requirements to each customer group to establish final rates. To prevent rate shock, the AUC found It necessary, just and reasonable to use a gradualism approach when implementing the final rates.

<u>Details of the Application</u>

Sage Water operates a water utility which began servicing the Prince of Peace site in 2019. The Prince of Peace site comprises the senior care community ("the Senior Care Community"), the Prince of Peace School ("the School") and 175 residential condominium units known as the Village ("the Village"). During the time of operation as a water utility, Sage Water has been charging the School, the Senior Care Community, and the Village a fixed monthly fee for water consumption and services. The AUC had approved interim rates of $57.04 for the Residential rate class, $24,200.00 for the Senior Care Community rate class, and $757.90 for the School rate class. These interim rates were approved and effective as of November 19, 2020.

Sage Water based its revenue requirement ("RR") forecast on operating expenses and requested a reasonable return instead of a return on rate base. It indicated that it does not have a rate base. Its parent company obtained the water utility assets in a bankruptcy proceeding and the utility assets were not assigned a value by the receiver.

<u>Discussion of Issues and Findings</u>

Contentious Issues

Issues were raised regarding twelve operating expense categories and the expense amounts. The categories at issue are those regarding corporate management fees, office and administration cost-sharing, repair and maintenance, site maintenance, pump maintenance, insurance, security, consultants, professional fees, legal, reasonable return, and approved revenue requirements.

The AUC found that the costs requested by Sage Water regarding office and administration, repair and maintenance, legal fees, and security monitoring were calculated appropriately and approved as reasonable.

Regarding corporate management fees and site maintenance costs, concerns were raised regarding the reasonableness of the amounts. However, following a comparison with other water utilities, the AUC found that allocating 10 per cent of the corporate management fees to the water utility is reasonable.

The AUC was concerned with the detail of explanation and justification provided regarding costs related to insurance and professional fees. While Sage Water provided some explanation, the AUC noted that the level of detail did not justify the significant increase of 15 per cent requested regarding insurance. Sage Water provided evidence for the increase in professional fees and some detail regarding the actual expenses for the periods. It noted that $4,500 allocated for the Specific Procedures Report will likely not be required for the 2021-2023 period unless requested by the Village.

As a result, regarding insurance, the AUC approved an increase of two per cent each year to account for inflation. Regarding professional fees, the AUC removed the unjustified and not sufficiently supported costs from each of the test periods. The AUC approved forecast professional fees of $1,421 for the stub period; $3,900 for fiscal 2022; and $3,978 for fiscal 2023, which was derived by applying a two per cent inflation factor to the approved amount for the 2022 fiscal year.

The AUC also emphasized that whenever possible, costs need to be allocated only to those rate payers benefitting from the specific service. Regarding pump maintenance, the AUC was satisfied by the explanation that all rate classes benefit from this service. However, the AUC found that the quantum was not sufficiently supported and disallowed a portion of related costs.

Concerning costs related to consultants, the AUC found that scheduled assessments and consultations regarding Sage Water's water system were scheduled to be completed in 2021. Accordingly, it disallowed the inclusion of consultant costs related to future assessments of the water system in rates for the fiscal years 2022 and 2023.

Reasonable Return

Sage Water explained that its parent company obtained the water utility in a bankruptcy proceeding where the utility assets were not assigned a value. As a result, a return on the rate base is not possible. It requested a reasonable return margin in its application as it has an obligation to provide water services.

Sage Water stated that the number of ratepayers is fixed and there is no opportunity to bring in additional customers. Given a fixed ratepayer base and revenues under $500,000, Sage Water considers its operational risk to be high as it has a reduced ability to recover unforeseen costs. Sage Water explained that it requested a 2.5 per cent return margin based on its review of AUC Decision 2941-D01-201570 for regulated electric utilities. Sage Water argued that "the decision outlines a reasonable rate of return at an after-tax margin in the range of 1.25% to 1.75% depending on the provider (for electrical services) with an allowable return margin of 1.5%".

Sage Water's request for a 2.5 per cent after-tax return on its approved costs was found to be reasonable and was approved. Regarding established ratemaking principles followed by the AUC, Sage Water would be entitled to a return based on the net book value of its assets. Sage Water has no discernible values for the capital assets that comprise the water operation. As a result, the AUC found that calculating a return component based on a percentage of costs was the next best alternative. The AUC added that this is consistent with the method used to determine the return for regulated rate option providers.

Rate Structure

Sage Water requested a change in its rate structure from a fixed fee to a two-step tiered structure, including a fixed monthly fee and a fee based on consumption.

The AUC found the proposed tiered rate structure mechanism contemplated by Sage Water to be inaccurate because averaging the quarterly meter reads into monthly averages may not reflect true monthly consumption. It could result in customers not being charged the second tier usage rates even though they may have used more than the first tier volumes in a particular month. Moreover, implementation of a rate based, in part, on water consumption, cannot be reasonably effected without a fully functional meter at the School.

In view of the anticipated transfer of the water utility to Rocky View County, the AUC found that by maintaining the current interim rate structure to develop final rates, the complexity of truing up interim rates to final rates under the tiered rate structure and the need for an immediate water meter replacement at the school would be avoided.

Final Rate Determination

Rates are designed based on approved revenue requirements. There is a minimum revenue requirement that a utility requires to operate and maintain its financial viability. The Sage Water utility business has been operating with a static customer base on fixed rates that were not designed with a proper allocation methodology. The AUC remarked that when the RR of a utility and the rates charged to recover the RR are not appropriately linked, aligning the two can be complicated.

Determining final rates for the three customer groups for each of the test periods starts with the approved forecast amounts for each of the operating expense categories and the reasonable return for each of the three test periods. The next step is to allocate the approved forecast amounts to each of the three customer groups. The allocation of approved forecast amounts to the three customer groups is intended to reflect the principle of cost causation. In the absence of a detailed cost-of-service study, which entails time and cost that is not likely to be warranted given the size of this water utility, the Commission considers that basing the allocation on the available water usage data is the fairest way to allocate the costs. While that data is imperfect given the absence of a fully functional meter at the School, it is the best evidence available to the Commission. It is also representative of the costs incurred. Once all costs are allocated to each of the three customer groups, the resulting monthly fixed rates for each of the three customer groups are calculated by dividing the total costs allocated to the customer group by the number of months in the test period and then by the number of customers. For each test period, the Commission counted the Senior Care Community as one customer, the school as one customer, and the Village as 175 customers.

The AUC compared the calculated rates to the existing interim rates paid by the customers. The result was an increase of at least 60 per cent for the School and the Village rate groups. The Commission typically considers any rate increase for a customer group that exceeds 10 per cent to constitute rate shock for the customers in that group. Typically, the Commission mitigates rate shock by “gradualism,” which is the practice of phasing in rate increases over a longer period of time to allow customers to eventually pay their fair share of the allocated costs. Because this significantly exceeds the rate shock threshold considered by the AUC, the AUC found that rate shock mitigation by “gradualism” was reasonable. Final rates for the stub period for the School and the Village would be set by increasing the current interim rates by 10 per cent. This will be followed by a further 10 per cent increase for the 2022 fiscal year and another 10 per cent increase for the 2023 fiscal year. The resulting rates for the Senior Care Community will be set to recover the remaining amounts of the approved revenue requirements for each of the test periods, after accounting for the revenues to be collected through the final rates for the School and the Village. True-up of Interim Rates to Final Rates.

The AUC noted that interim rates are approved to function as placeholders until final rates are approved. Interim rate orders are used by the AUC to prevent rate shock and to ensure the financial integrity of a utility while final rates are being established. Sage Water’s final rates are higher than interim rates for the School and the Village and lower than the interim rates for the Senior Care Community. This means that the School and the Village are required to pay the difference to Sage Water through a rate rider, and the Senior Care Community is entitled to be reimbursed through a rate rider.

Sage Water’s total revenue requirement, as adjusted, for the 2020-2023 period was approved and the approved bill amounts set out in Table 9 of the decision was approved on a final basis.

CANADA ENERGY REGULATOR

Trans Mountain Pipeline ULC Trans Mountain Expansion Project Notice of Motion and Constitutional Question, CER Letter Decision and Orders AO-001-MO-002-2021 and MO-031-2021

TMEP - Municipal Bylaws

In this decision, the Canada Energy Regulator ("CER") considered an application filed by Trans Mountain Pipeline ULC ("Trans Mountain") regarding the application of Bylaws of the City of Burnaby ("Burnaby") regarding access and tree clearing near Burnaby. The CER decided that the sections of Bylaw in question are not applicable under the doctrines of federal paramountcy and interjurisdictional immunity.

CER Analysis and Findings

Pursuant to Certificate OC-065, Condition 2, Trans Mountain is required to implement all the commitments it has made in its project application or on the record of the related proceedings. Among these is the commitment to "apply for, or seek a variance from, all permits and authorizations that are required by law." Condition 1 requires Trans Mountain to comply with all conditions unless the CER otherwise directs.

Trans Mountain sought a determination that Section 3 of Burnaby's Bylaw No. 10482 ("Tree Bylaw") and 24(1) of Burnaby's Bylaw No. 4299 ("Access Bylaw") was inapplicable, invalid or inoperative under the doctrines of interjurisdictional immunity and/or federal paramountcy..

Findings of Fact Regarding Tree Clearing and Access

The CER determined that additional tree clearing is needed to construct the Trans Mountain Expansion Project (the "Project") as designed and approved. Trans Mountain submitted that Burnaby's past conduct demonstrates that it will not issue Tree Cutting Permits for the Project under any circumstances. Based on information submitted by Trans Mountain, the Majority found as a fact that Burnaby will not issue Tree Cutting Permits for the Project.

The rationale provided by Burnaby for not granting the Access Permit was that it had not been provided with a satisfactory explanation for why additional access was necessary to construct the pipeline, nor why the application for the North Road (South) Access alternative was not made at the same time as that for the North Road (North) Access option.

The CER determined that Trans Mountain had provided Burnaby with an explanation with respect to both matters. The CER also determined that Trans Mountain's evidence demonstrates that North Road (North) Access was required earlier in the construction schedule and that Access Permits are only valid for one month. In the absence of evidence demonstrating that application must be brought for both access points at the same time, it was not reasonable for Burnaby to deny the application on that basis in any event.

Constitutional Principles

Where there are inconsistent or conflicting validly enacted federal and provincial laws, the federal law prevails. Paramountcy renders the provincial law inoperative to the extent of the inconsistency or conflict. In order for paramountcy to apply, there must be an inconsistency or a conflict between federal and the provincial law. A conflict or inconsistency can arise if there is an impossibility of dual compliance or a frustration of a federal purpose. Paramountcy applies where an application or operation of the provincial law would frustrate the purpose of the federal law. If it is possible to interpret the two laws in a manner to avoid conflict or inconsistency, that is preferable to an interpretation that results in a conflict or inconsistency. The CER was of the view that where dual compliance is theoretically possible, such as in this case, the application of paramountcy turned on whether there was a frustration of a federal purpose.

Under the doctrine of interjurisdictional immunity, undertakings falling within federal jurisdiction, such as the Project, are immune from otherwise valid provincial laws (and by extension municipal bylaws) that would have the effect of impairing (not just affecting) a core competence of Parliament or vital part of the federal undertaking. First, it must be determined if the provincial law trenches on the protected core of a federal competence. If so, it must be determined if the provincial law's effect on the exercise of the protected federal power is sufficiently serious to invoke the doctrine of interjurisdictional immunity.

The CER noted that the doctrines of paramountcy and interjurisdictional immunity require an actual, rather than a speculative or hypothetical, conflict or impairment

Application of Constitutional Principles to Tree Clearing

Considering the finding that Burnaby will not issue any permits for tree cutting for the Project, the Majority was of the view that Trans Mountain's application is reasonable and not premature. As tree clearing is required for the Project's construction, the operation of the Tree Bylaw frustrates a federal purpose in these circumstances. The CER therefore found that the doctrine of paramountcy applies to render section 3 of the Tree Bylaw inapplicable, invalid, or inoperative to the additional tree clearing and any Future Tree Clearing.

With respect to interjurisdictional immunity, the Majority found that Burnaby's refusal to issue Tree Cutting Permits trenches on the protected core of federal competence. Because the removal of trees is required to construct the Project, as designed and approved, this effect is sufficiently serious to invoke the doctrine of interjurisdictional immunity in respect of section 3 of the Tree Bylaw.

Application of Constitutional Principles to Access

The CER unanimously determined that the application of the Access Bylaw frustrates a federal purpose in these circumstances. Accordingly, the doctrine of paramountcy applies to render section 24(1) of the Access Bylaw inapplicable to the construction of the North Road (South) Access. The CER further unanimously found that Burnaby's denial of Trans Mountain's Access Permit application trenches on the protected core of federal competence. It found that this effect is sufficiently serious to invoke the doctrine of interjurisdictional immunity in respect of section 24(1) of the Access Bylaw.

Relief from Certificate Condition 2 in Respect of Tree Clearing

The CER Majority determined that construction of the Project, which has been found to be in the public interest, requires the removal of trees. If an exemption from Condition 2 is not granted, Trans Mountain will not be able to obtain the Tree Cutting Permits necessary to conduct this work.

For the additional tree clearing, Trans Mountain committed to following the mitigation, monitoring, and compensation measures to which it committed in the 2020 Motion. It further made additional commitments in its 2021 Motion. These commitments essentially bind Trans Mountain to the same obligations to which it would have been subject if Tree Cutting Permits had been issued by Burnaby.

The Majority has determined that it is in the public interest to relieve Trans Mountain of the requirement under Certificate Condition 2 to obtain Tree Cutting Permits under section 3 of the Tree Bylaw with respect to the additional tree clearing and any Future Tree Clearing.

Relief from Certificate Condition 2 in Respect of Access

Because the CER concluded that the safe and efficient construction of the Project, which has been found to be in the public interest, requires the North Road (South) Access, the CER unanimously determined that it is in the public interest to relieve Trans Mountain of the requirement under Certificate Condition 2 to obtain an Access Permit under section 24(1) of the Access Bylaw to construct the North Road (South) Access. Trans Mountain committed to adhering to the mitigation measures submitted to Burnaby within and pertaining to the Access Permit application.