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.

IN THIS ISSUE:

ALBERTA ENERGY REGULATOR

Edition of Directive 040, AER Bulletin 2021-34
Oil and Gas - Wells

The AER released a new edition of *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*. In the new edition:

- guidance for minifrac tests, also known as diagnostic fracture injection test, has been updated to align with the current practice;
- the exemption eligibility criteria for the initial pressure test requirement for new oil, gas and step-out wells has been expanded;
- the requirement to conduct an absolute open flow deliverability test on new gas wells was removed; and
- the requirement to conduct annual pressure tests for oil and gas pools under primary production was rescinded.

Update on AER Review of Administration Fee (Industry Levy), AER Bulletin 2021-35
Industry Levy - Facilities

In 2019, the Government of Alberta permitted the AER to review the administration funding of the AER. In two phases, the AER evaluated the calculation of the fees.

In Phase 1, the AER reduced the base fees for service wells and wells producing less than 600 cubic meters per year for 2020/2021.

In Phase 2, the AER reviewed other jurisdictions and evaluated options to change based on jurisdictional review and survey results. The AER also held workshops with each industry sector (oil and gas, oil sands, and coal) to review proposed changes.

The objectives of this review were the fair allocation of the levy to the sectors it regulates. Following its findings from Phase 2, the AER determined that the following changes are the most effective:

- Base the levy allocation on a three-year rolling average of AER staff effort for each sector (i.e., full-time equivalent personnel supporting the sector), starting with the invoices issued in September 2021. Currently, levy allocations are based on the estimated AER staff effort spent supporting each sector. Levies for pipelines, larger facilities, and new industry sectors, such as geothermal, would also be calculated using the three-year rolling average.

- Add two additional production classes for wells producing over 8000 m^3/year and new base fees for each class to the rate tables for the oil and gas sector for Fall 2021.

- Include inactive oil and gas wells in the oil and gas sector levy in the rate tables for the oil and gas sector for 2021, charging a base fee of $42/well before applying an adjustment factor that ensures that the total administration fee collected for the sector satisfies the revenue requirement for the AER.

- Introduce a new levy on pipelines based on pipeline classes determined by their diameter. The levy would be phased in for spring 2022 and reflect the total amount of staff effort by 2024 as each year of effort is determined.

- A new larger facility levy that would apply to 26 gas plants with approved inlet rates greater than 10 million m^3/day and four stand-alone oil sands facilities. The larger facility sector allocation would be prorated based on gas plants' inlet rate and production capacity for stand-alone facilities. The levy will be phased in for spring 2022 and reflect the total staff effort by 2024 as each year of effort is determined.

A review of the changes and decision regarding the proposed changes from the Government of Alberta is expected in the Fall of 2021.

For the 2021/2022 levy, the Government of Alberta approved a total industry levy of $207.6 million.

Stress Corrosion Cracking on Insulated High-Temperature Pipelines, AER Bulletin 2021-36
Oil and Gas - Pipeline Inspections

The AER observed numerous pipeline incidents over the past five years resulting from stress corrosion cracking. The incidents involved high-temperature carbon steel surface pipelines that had mineral wool insulation and aluminum cladding but no external corrosion barrier under the insulation. The AER noted that the pipelines lacked this barrier because of their high operating temperature. The AER was concerned with these incidents, as they were occurring in areas of relatively low stress, such as straight sections.

The AER emphasized that licensees are required to consider the risk of corrosion cracking as part of their integrity management program.

Following the occurrences, the AER recommended that licensees:

- Conduct an engineering assessment to determine whether the insulated pipelines are susceptible to stress corrosion cracking and what portions could be susceptible to failure;

- Inspect pipelines that may be at risk. If there is a potential that the insulation is wet, select representative locations on the pipeline and conduct investigative inspections to identify corrective actions;

- Evaluate and repair potential defects according to *CSA Z662-19* clauses 10.10 and 10.10.5;

- Consider replacing old cladding and incorporate new cladding designs and techniques into pipeline construction practices to help prevent moisture from accumulating;

- Review leak detection programs, including right-of-way inspection, and adjust as necessary;

- Report any leak and rupture incidents to the AER as per standard reporting requirements; and
- Advise the local AER field center of insulated pipelines with stress corrosion cracking, even if they are not leaking, and adjust inspection and leak detection programs in response to findings.

New Statement of Concern Form, AER Bulletin 2021-38
Submission Process

On September 28, 2021, the AER released a new statement of concern ("SOC") form. The SOC form was updated to make the submission process more user-friendly and to facilitate a better understanding of concerns of SOC filers by the AER. The update allows the following.

- SOC filers can now submit the form and supporting documents online, as well as by email or regular mail.
- The new form is in HTML format and is embedded on the AER website. As a result, the form can be viewed and submitted on various devices (e.g., cell phone, tablet, laptop, etc.).
- The PDF version of the form has also been updated.
- The AER added more detailed instructions to help filers clearly identify each concern and any documentation they wish to include.
- The AER included information about additional resources that support engagement between concerned parties and applicants, such as the AER's alternative dispute resolution program.
- Permissions associated with confidentiality and supplemental information are now requested in the beginning to enhance clarity and efficiency of the SOC process and a mechanism for SOC filers to request permission to file supporting documentation after the SOC filing deadline has been created.

The AER encourages SOC filers to use the new HTML format.

***Request for Regulatory Appeal by Clint and Ray Jacula Regarding Licences Issued to Husky Oil Operations Ltd.,* AER Application 1929563**
Appeal - Responsible Energy Development Act

In this decision, the AER denied a request under Section 38 of the *Responsible Energy Development Act* ("*REDA*") for a regulatory appeal (the "Request"), filed by Clint and Ray Jacula (the "Jaculas"), of the AER's decision to approve Licences issued to Husky Oil Operations Ltd. ("Husky").

<u>Parties' Submissions</u>

In their Request, the Jaculas submitted that Husky failed to meet with the the Jaculas and their neighbours about the project and its impact. The Jaculas requested relocation of the drilling and compensation for potential losses to cattle production, water, hazardous chemicals and vegetation. The Jaculas also requested proof from the AER showing how, according to Section 57 of the *Law of Property Act*, it can approve drilling and removal of their clay and marl from surface drilling.

<u>AER Decision</u>

The AER made its decision under the *Oil and Gas Conservation Act* ("*OGCA*"). The proposed project is located on land adjacent to the land owned by the Jaculas, but portions of drilling associated with the project will take place under the land owned by the Jaculas. As a result, the AER found that the Jaculas are potentially directly and adversely affected by the decision and eligible to request a regulatory appeal of the licenses under Section 36(b)(ii) of the *REDA.*

Merits of the Request

Under Section 39(4) of the *REDA,* the AER can dismiss a request for regulatory appeal if the AER considers the request to be frivolous, vexatious or without merit, or if for any other reason the AER considers that the request is not properly before it.

The AER found that Husky had contributed to establishing and maintaining a neighbourly relationship by demonstrating openness to resolving the Jaculas' concerns outside of a formal AER process. The AER held that matters concerning compensation for potential losses to cattle production or damage from hazardous chemicals in general, and to vegetation in particular, as raised by the Jaculas, are outside of its jurisdiction. The AER also found that the Jaculas' concerns regarding impacts to traffic was outside of its jurisdiction.

The Jaculas raised concerns with directional drilling. The Jaculas' proposed relocation of the drilling on their land. Husky submitted that the drilling locations proposed by the Jaculas would result in duplication of resources and increased safety risk. These results would be contrary to Section 4(c) of the *OGCA* and Section 2(1) of the *REDA.*

The AER found that approvals relating to drilling and removal of clay and marl are outside its jurisdiction. The AER noted that issues concerning potential jeopardy to the Jaculas' water are adequately addressed as Husky must comply with the requirements in AER Directive 008 and *Directive 009: Casing Cementing Minimum Requirements*, which aims to design appropriate depths of surface casing and meeting the casing cement requirements to assist with well-control and groundwater protection. Husky also offered to cover all reasonable costs for the Jaculas to retain an independent consultant to test the water well before and after drilling.

While the AER has concluded that the Jaculas are eligible to request a regulatory appeal of the licenses, the AER found that their appeal is without merit and not properly before the AER.

Reconsideration of Northwestern Utilities Ltd. As Licensee of Record of Certain Wells Previously Held by the Lloydminster Development Company, **AER Application 1934332**
Responsibility for Wells

In this decision, the AER determined it is appropriate to reconsider, without a hearing, its 1985 decision to transfer responsibility for certain wells previously licensed to the Lloydminster Development Company ("LDC") to Northwestern Utilities Ltd ("NUL") when NUL amalgamated with the Lloydminster Gas Company ("LGC"). The AER further decided to revoke its 1985 decision and correct its records to remove NUL as the licensee of record for wells not licensed to LGC before amalgamation. The 46 wells subject to this reconsideration decision (the "LDC Wells") are listed in Appendix 1 to the AER's decision.

<u>Background</u>

LDC and LGC were related but distinct entities, sharing a business associate ("BA") code. Years after their registration, LGC and NUL amalgamated into one entity, NUL. The AER noted that when amalgamated, the responsibility for all wells associated with the shared BA codes was transferred to NUL in the system of the Alberta Energy and Utilities Board and the Energy Resource Conservation Board (the "Regulator"), the predecessors to the AER.

The AER reviewed the records related to the LDC Wells, including the licenses, drilling reports, and reclamation certificates, and found that LGC was not the last licensee of any of the LDC Wells.

The AER noted that Section 42 of the *Responsible Energy Development Act* ("*REDA*") provides it with authority to reconsider its decision. It noted that it would only exercise this discretion under the most extraordinary circumstances, where it is satisfied there are exceptional and compelling grounds to do so. The AER has determined such circumstances exist here.

The AER found that when NUL and LGC amalgamated, responsibility for the LDC Wells was transferred to NUL because LDC and LGC shared a BA code. However, the requirement that a licensee holds a BA code was not introduced until 2000, after the amalgamation and after the LDC Wells had been abandoned or reclaimed. LDC and LGC sharing a BA code was not a reason that justified transferring responsibility for the LDC Wells to NUL. Accordingly, the AER found that extraordinary circumstances exist that provide exceptional and compelling grounds for the AER to exercise its discretion to reconsider, without a hearing, the Regulator's decision to transfer responsibility for the LDC Wells to NUL.

Decision on Reconsideration

The AER determined that there is no reason to identify NUL as the licensee of record for the LDC Wells. Accordingly, the AER revoked that 1985 decision to transfer responsibility for the LDC Wells to NUL. The AER noted that this reconsideration does not relieve ATCO Gas and Pipelines, as NUL's successor of any obligation it may have under Part 5 of the *Environmental Protection and Enhancement Act*.

ALBERTA UTILITIES COMMISSION

Consultation on Proposed Amendments to AUC Rule 023, AUC Bulletin 2021-017

Rules - Rates

The AUC issued Bulletin 2021-017 seeking feedback on amendments to Rule 023: *Rules Respecting Payment of Interest*.

The proposed amendments aim to simplify Rule 023 and ensure broad application of the rule. The AUC noted its consideration of the following changes:

- General application of Rule 023 to all outstanding balances and adjustments of rates, tolls or charges and any other costs that are subject to the AUC's jurisdiction;
- Simplification of the criteria applied to a request for the payment of interest;
- Reduction of the period for which a balance must be outstanding;
- Removal of a specific materiality threshold; and
- Use of the Bank of Canada policy rate instead of the Bank of Canada bank rate.

The proposed changes are intended to apply to applications on a go-forward basis. Once the amended rule is approved, following the AUC's approval of the amended rule, deferral accounts and balances that have been awarded interest at a weighted average cost of capital ("WACC") or another interest rate will be honoured for the time periods for which they were approved, after which, a request for any rate other than the rate specified under Rule 023 will be required to justify a different rate.

Participation in the consultation is possible until October 7, 2021.

Consultation on Rule 022: Rules on Costs in Utility Rate Proceedings, AUC Bulletin 2021-018

Stakeholder Consultation - Cost Recovery

The AUC initiated a review of the rules regarding cost recovery in rates proceedings to improve participation and encourage efficient, issue-focused proceedings. The AUC will focus first on Rule 022: *Rules on Costs in Utility Rate Proceedings*. The AUC will review Rule 009: *Rules on Local Intervener Costs* in the future.

This consultation aims to obtain feedback describing how Rule 022 can be changed to promote consistent and effective participation in AUC proceedings. A further objective is to clarify the rule for participants while also respecting that these costs are ultimately paid by ratepayers and should be limited to what is necessary, efficient and reasonable in the circumstances.

The AUC scheduled a virtual stakeholder consultation session to hear topics addressed in this bulletin and other comments on costs recovery in utility rate proceedings on December 8 and 9, 2021. Until November 17, 2021, the AUC is seeking responses on the following broad topics:

- Utility cost recovery process;
- Eligibility for costs;
- The scale of costs and claims for professional fees;
- Process for costs awards; and
- Other issues or considerations.

***Alberta Electric System Operator Cancellation of the Needs Identification Document Approval for the Peace Butte Wind Energy Connection,* AUC Decision 26828-D01-2021**
Rescinded Approval

In this decision, the AUC rescinded the needs identification document approval for the Peace Butte Wind Energy Connection Project (the "Approval"). The AUC rescinded the Approval in response to an application from the Alberta Electric System Operator ("AESO") because the system access service request was canceled.

Discussion

In 2013, the Approval was granted for the need to connect the approved Peace Butte Wind Power Project and Tothill 219S Substation to the Alberta Interconnected Electric System ("AIES") by constructing a new 138-kilovolt transmission line.

After the AUC had issued the necessary permits and licenses, the AUC issued various extensions to construct the wind power project and the connection facilities. In May of 2021, the AUC rescinded the Approval for the wind power project and the permits and licenses for the corresponding substation. As a result, there was no longer a need to connect the power plant. The AESO canceled the system access service request for the project on May 12, 2021.

AUC Findings

The AUC accepted that the approved need for the connection facilities was no longer required. The AUC accordingly rescinded the needs identification document approval. As the connection order for the wind power had not yet been rescinded, the AUC also rescinded the order for connecting the new transmission line to the Tothill 219S Substation.

***Alberta Electric System Operator Proposed Amendments to Sections 103.4 and 103.6 of the ISO Rules,* AUC Decision 26641-D01-2021**
FEOC - Updates

In this decision, the AUC approved changes to Section 103.4 of the Independent System Operator ("ISO") rules, *Power Pool Financial Settlement*, and Section 103.6 of the ISO rules, *ISO Fees and Charges* (collectively, the "Financial Settlement Rules"), proposed by the Alberta Electric System Operator ("AESO").

Background

The AESO submitted that the Financial Settlement Rules set out requirements for the AESO and market participants for the financial settlement of the power pool. The AESO proposed amendments allowing electronic funds transfer and clarifying the interest calculation and other rights relating to non-compliance with metering requirements. The AESO also made process-related revisions to align with its current red tape reduction initiative. Following stakeholder consultation, the AESO reinstated several process requirements it had removed in the first draft of the amendments.

The AESO requested that the AUC approve the updated Financial Settlement Rules according to Section 20.21 of the *Electric Utilities Act*.

AUC Findings

The AUC noted the absence of opposition to the AESO's application. The AUC approved the proposed amended sections 193.4 and 103.6 of the ISO rules as applied for.

***Alberta Federation of Rural Electrification Associations Decision on Preliminary Question Application for Review of Decision 25916-D01-2021 Fortis Alberta Inc. 2022 Phase II Distribution Tariff Application,* AUC Decision 26756-D01-2021**

Review and Variance - Cost Allocation

In this decision, the AUC denied the application from the Alberta Federation of Rural Electrification Associations ("AFREA") to review and vary AUC Decision 25916-D01-2021 (the "Decision").

Background

The Decision related to the Phase II application from FortisAlberta Inc. ("FortisAB") in which the AFREA was an intervener. In this decision, the first stage of the two-stage review process, the AUC found that there were not sufficient grounds to review the original Decision. The review application concerned the AUC's findings regarding the overlap of FortisAB service areas with those of certain Rural Electrification Associations ("REAs") and FortisAB's distribution cost allocation and rate design.

Review Panel Findings

This application was subject to the amended AUC Rule 016: *Review of Commission Decisions*. The updated Rule 016 no longer includes errors of law or jurisdiction in the scope of a review by the AUC. The AUC determined that the AFREA raised two grounds that are errors of law and therefore outside the scope of the AUC's review process.

The AUC noted that the application was confusing, unclear, and inconsistent and cautioned that the burden to provide clear grounds, supporting submissions, and references to the original record to support the application for review lies with the party seeking review.

The Hearing Panel Erred in Finding that FortisAB had Historically Recovered Integration Operation Costs from its Customers

The AFREA argued that the AUC had made a factual error in paragraph 185 of the Decision by ignoring or not considering evidence including commercial arrangements made between REAs and FortisAB that, contrary to the AUC's findings, indicated that FortisAB had historically recovered integrated operations costs from its customers, not REAs.

The AUC disagreed. It noted that a panel's silence on specific submissions or evidence does not always indicate that the information was ignored. The AUC further referred to paragraphs in the Decision regarding the background that indicated that it had considered all evidence, even if some pieces were not discussed in the published Decision.

Further, the AUC noted that the Decision discussed prior proceedings in which the issue of FortisAB's integrated operations costs had been considered. The AUC further referred to sections in the Decision regarding information request responses noting how FortisAB had historically accounted for contributions paid to and received from REAs. The AUC noted that those references clearly demonstrated that the panel explicitly considered evidence regarding FortisAB's accounting of integrated operation costs in its tariff, the type of costs historically contemplated under the Integrated Operations Agreements ("IOAs"), as well as the impact of changing ownership of assets on cost allocations.

Accordingly, the AUC found that there was no evidence to suggest that the information referred to was disregarded in arriving at the Decision. The AFREA did not show that a factual error exists in paragraph 185 of the Decision on a balance of probabilities.

The Hearing Panel Erred by Failing to Address the Quantification Issue

The AFREA submitted that the hearing panel failed to address the quantification issue raised by the AFREA for the equity provided to the predecessors of FortisAB in exchange for cooperation with the building of the Alberta Interconnected Electric System ("AIES"). The AFREA argued that the hearing panel should, at minimum, have referred to negotiations and arbitration in determining if FortisAB's applied for costs associated with integrated operations were reasonable.

The AUC was not convinced that the evidence referred to by the AFREA was ignored in the Decision. The AUC repeated that there is no requirement that a hearing panel address in its decision all the evidence that was put before it in a hearing. The AUC found that there was no evidence to suggest that information had been disregarded. The AFREA was found not to have shown that there was an error in fact or mixed fact and law by not considering the issue of quantification for the equity provided to the predecessors of FortisAB in exchange for cooperation with building the AIES. The request for review on this ground was denied.

The Hearing Panel Erred in Finding the Methodology to Determine Costs Associated with and Attributable to Integrated Operations was Reasonable

The AFREA argued that the hearing panel had erred in finding that the methodology to determine costs associated with and attributable to integrated operations with REAs was reasonable. It argued that the AUC failed to apply the facts presented by the AFREA, indicating that the IOAs provided for costs that are negotiated and paid under the terms of the IOAs in effect at the time as transmission or system access costs.

The AUC again found that there was no evidence to suggest that the information and evidence had been disregarded. The AFREA did not show that, in finding that the methodology to determine costs associated with and attributable to integrated operations with REAs was reasonable, the AUC had erred by failing to apply the facts presented by the AFREA.

The Hearing Panel Erred by Making Findings with Incomplete Information

The AFREA argued that the AUC did not have evidence from REAs regarding FortisAB's costs associated with its integrated operations with REAs on the record of the original proceeding. The REAs provided full evidence in the negotiations and arbitrations that occur under the part of the *3R Regulation*. The AFREA argued that it is an error of mixed fact and law for the hearing panel to make findings with incomplete information.

The AUC, referring to sections of the Decision, found that the panel of the Decision considered the information and evidence appropriately. The AFREA appeared to disagree with the weighting and treatment of evidence. The objective of a review and variance is not to retry an application. As the AFREA did not convince the AUC that an error of fact, law or mixed fact and law exists on a balance of probabilities, the AUC denied the application on this ground.

The Hearing Panel Erred by Classifying REAs as "End Users"

The AFREA argued that, because REAs are not the same as FortisAB's other end users which are FortisAB's customers, the AUC had made an error of mixed fact and law by describing REAs as "end users". The AFREA argued that the result of this finding is that the AUC classified REAs as customers, which impacts their ability to negotiate.

The AUC noted that REAs were not described as "end users" in the Decision but were referred to as "users" of FortisAB's system. This description was made in the section of the Decision addressing whether some portion of

FortisAB's total costs should be allocated to REAs and if the determination of costs related to REAs should follow a similar method to that of customers and rates classes.

The AUC determined that in the Decision, the objective of differentiating between "REAs" and "Fortis's own customers" and between "REAs" and "other users", was to distinguish between REAs and FortisAB customers.

The AFREA did not show that this argument fulfilled the requirements to justify a review.

AUC Decision

In answering the preliminary question, the AUC found that the AFREA did not meet the requirements for a review of the Decision and the application for review was dismissed.

***AltaLink Management Ltd. and ATCO Electric Ltd. Nilrem to Vermilion Transmission Development Project,* AUC Decision 26145-D01-2021**

Routing of Transmission Facilities - Increased Costs

In this decision, the AUC denied the applications by AltaLink Management Ltd. ("AltaLink") and ATCO Electric Ltd. ("AE") to construct and operate their proposed transmission facilities, as it did not have adequate information to assess the routes before it and other viable route options were not properly assessed.

Introduction

The AUC already approved the need for this project as part of the Provost to Edgerton and Nilrem to Vermilion Transmission Development. In this decision, the AUC had to consider whether it is in the public interest to approve the transmission facilities currently before it, having regard to their social, economic and environmental effects.

AltaLink and AE each applied to construct and operate a single-circuit, 240-kilovolt ("kV") transmission line, which would be initially energized at 138 kV and 144 kV, respectively. AltaLink's portion, designated as Transmission Line 333L, was approximately 75 to 80 kilometers long, from the existing Nilrem 574S Substation to the service territory boundary with AE. AE's portion, designated as Transmission Line 7L333, was approximately 13 kilometers long, from the proposed Drury 2007S Substation to the service territory boundary with AltaLink. Both transmission facility owners ("TFOs") also filed applications to interconnect the two transmission lines.

A number of landowners near the proposed development intervened in the proceeding. The Consumers' Coalition of Alberta ("CCA") intervened to address cost-related matters that may affect ratepayers.

Inability to Properly Assess Routing

The AUC undertook an extensive assessment of the applications and proceeding materials in an attempt to determine the lowest impact routes. The number of variants, along with the number of ways that the segments can be combined, resulted in many different overall routes that the AUC could potentially approve. To narrow this down, the AUC first considered the local variants, often segments within segments, in an attempt to determine which would have lower impacts before it moved on to considering larger segments. This was an iterative process. The AUC also conducted a holistic analysis to assess the impacts of overall combined routes, taking into account that the interrelated nature of adjacent segments meant they could not be considered in isolation.

Ultimately, because of the flawed nature of the applicants' routing process and the discrepancies in the cost information provided, the AUC could not select a route based on the information before it. The AUC noted that it was aware that denying these applications was not without its own impacts. The need for this project has been approved, including dates by which the project should be in service. Denying the applications was likely to result in delays to the in-service date that in turn has the potential to negatively affect generators intending to connect in the area and load that will continue to be served by an area transmission system that does not meet the AESO reliability standards. Denying the applications also means that some interveners may have to go through this process again. In spite of these drawbacks, the AUC decided that it had no other option but to deny the applications as it was of the view that to do anything else would run counter to the public interest and would erode the public's trust in the regulatory process.

Lack of Coordination Between AltaLink and AE Resulted in Incomplete or Improper Consideration of Routing Options

The AUC held that the applicants' routes are not independent of each other and must be considered together. By considering its routes independently of AE, AltaLink may have identified a route with the lowest impacts within its service territory but one that must connect to a higher-impact route in AE's service territory. A route that would have higher impacts may exist within AltaLink's service territory but would nevertheless result in a lower overall impact route because it connects to a lower impact route in AE's service territory. It appeared to the AUC that this scenario had arisen in this proceeding, and in particular, that the applicants failed to understand and appreciate the overall costs of certain routes properly.

AltaLink and AE Failed to Provide Complete and Accurate Information for Assessment of Overall Routes

The applicants' decision to not conduct an overall route assessment and only consider routing within their respective service territories meant that there was not one place where the AUC could look to see the metrics of an overall route. While the AUC attempted to piece together the available evidence to determine which route combinations could be approved, it could not do so. The lack of complete and accurate information, particularly the cost estimates, rendered it impossible for the AUC to assess the routing options before it properly.

While the AUC appreciated that it could be inefficient to prepare detailed cost estimates for every route combination, it must have accurate cost information to assess which routes are in the public interest properly. The AUC noted that not only did it require multiple rounds of information requests to obtain segment-by-segment costs from AltaLink, the information the AUC ultimately received underestimated the cost differences between certain routes by a margin of 40 percent. It was therefore difficult for the AUC to rely on any of AltaLink's segment cost estimates given this level of discrepancy. The AUC noted its expectation that AltaLink, and all applicants, will take measures to ensure that they provide more accurate segment cost estimates in the future.

The AUC was also concerned with the magnitude of the cost variances between the different variants for AltaLink and AE. Based on the figures provided to the AUC, it appeared as if AltaLink's costs are more than three times those of AE's to build the same length of transmission line. The AUC noted that AltaLink and AE proposed different transmission structures and conductors for transmission lines only exacerbated the difficulty in comparing routes. AltaLink's proposal to predominantly use steel monopole structures and AE's proposal to use wooden H-frame structures may contribute to these differences. The AUC held that despite the considerable time spent on the topic, the AUC never received a satisfactory answer for why the TFOs arrived at different solutions. The AUC noted its expectation that should AltaLink and AE's cost estimates continue to have significant variances for similar length routes when they re-apply, they will clearly outline the reasons for the differences.

Without relying on the cost estimates or assuming that the TFOs' estimates are comparable, the AUC found that it could not discharge its mandate to determine which routes are in the public interest.

Failure to Iteratively Assess Routes

The applications were initially placed in abeyance due to what the AUC considered a material deficiency and to allow routing alternatives to be finalized. The AUC considers it prudent for applicants to continue to consult with parties even after the application is filed and recognizes that application amendments may arise in an attempt to mitigate parties' concerns or as a result of new information. The AUC, however, noted that in this matter, it appears as if the applicants knowingly filed applications they knew were incomplete or subject to change. The AUC questioned whether time pressure to move the project forward resulted in the applicants cutting short the iterative routing process and finalizing routes prematurely. The AUC noted that it is incumbent upon applicants to ensure that they consider all available options through a robust routing process.

Assignment of Project to Both TFOs Resulted in Increased Costs

The AUC was of the view that not only did the assignment of the project to two TFOs and the lack of coordination result in issues with routing, it also resulted in unnecessary costs. While the AESO is responsible for determining who is eligible to apply for transmission facilities based on the TFOs' service territories under Section 24 of *Transmission Regulation*, that section nonetheless gives the AESO the discretion to assign projects to a TFO other than on the basis of geographic areas.

While the AUC understands that generally speaking, there are merits to having TFOs construct and operate facilities within their respective service territories (for instance, they may have existing relationships with landowners that would make consulting easier or more efficient), it is not convinced that the benefits outweighed the costs in this instance. The AUC emphasized that where a transmission line is assigned to multiple TFOs, the TFOs must strive to coordinate to reduce the costs and impacts of the project. It is not convinced that AltaLink and AE successfully did so in this instance, and this failure to properly coordinate may result in the AUC deeming costs to be improper or imprudent at a later date.

Other Concerns

Schedule Management and Cost-benefit of Major Decisions

The CCA submitted, and the AUC agreed that the AESO and the TFOs must proactively and continuously manage the project in-service date to avoid construction in time frames when unnecessary costs will be incurred and meeting an in-service date provides little or no benefit. The AESO and TFOs' responsibility to proactively manage their schedules is particularly critical in light of the denial of these applications.

The CCA submitted that a cost-benefit analysis should be conducted of any key decisions relating to the proposed facility additions to ensure proposed project designs and associated expenditures will add adequate and optimized value to ratepayers. The AUC agreed, however, the AUC did not propose to prescribe requirements on the type and timeline for a cost-benefit analysis. The TFOs stated that they conduct cost-benefit analyses and the AUC noted its expectation that they will continue to do so and be able to justify decisions based on those analyses in future applications.

Finally, the CCA stated that the schedules and cost estimates provided by the TFOs in their applications did not provide sufficient detail. Inadequate schedules pose the potential for unforeseen delays and additional costs; inadequate cost estimates further pose a greater risk of being inaccurate. The TFOs provided more in-depth schedules in response to CCA information requests. The AUC found this additional detail to be useful and the TFOs should endeavor to provide more detailed schedules in future facility applications.

Decision

The AUC found that it was not in the public interest to approve the applications as filed. The AUC found that the applicants' routing process was flawed and that there were discrepancies in the cost estimates provided that could not be resolved. The AUC was, therefore, unable to properly weigh the impacts of the various route options to conclude that it was in the public interest to approve any of the routes before it, having regard to the routes' social, economic and environmental effects.

Given the approved need for this project, AltaLink and AE were directed to re-apply for the transmission facilities.

Apex Utilities Inc. 2021-2022 Unaccounted-for Gas Rider E and Rider H, **AUC Decision 26740-D01-2021**

Gas - Rates

In this decision, the AUC approved Rate Rider E of 0.97 per cent and Rate Rider H of 0.98 per cent, as filed by Apex Utilities Inc. ("AUI").

Background

Rider E and Rider H are designed to recover the amounts associated with unaccounted-for gas ("UFG"). Rider E recovers the amount of UFG associated with producer transportation service and Rate Rider H the amount associated with Natural Gas Settlement System ("NGSS") processes.

Each rate rider is calculated using the most recent five-year averages of AUI's annual UFG percentages. Rate Rider H is further calculated in compliance with Rule 028: *Natural Gas Settlement System Code Rules.*

In previous decisions, the AUC has noted that it accepts that not all UFG can be eliminated but that it expects the amounts to decrease. The AUC had directed AUI and its predecessor AltaGas Utilities Inc. to quantify causes of UFG, to provide reasons for fluctuations in UFG, and to provide further specified information regarding UFG.

Analysis of Issues

UFG Calculations and Rider E and Rider H Amounts

AUI did not propose a change to the method of calculating Rate Rider E and Rate Rider H. For the determination of UFG amounts for Rider E for 2021-2022, AUI provided calculations yielding a historical five-year arithmetical average of 0.97 per cent. For Rate Rider H, the calculations submitted provided a five-year average of 0.98 per cent.

The AUC reviewed the calculations, which were based on the years 2017-2021, and was satisfied that the methodology applied was consistent with previous decisions. The 2021-2022 UFG amounts of 0.83 per cent and 0.84 per cent for Rider E and Rider H are below the five-year averages of 0.97 per cent and 0.98 per cent, respectively. The AUC also noted that the downward trend in UFG, indicated in the calculations submitted by AUI, could be attributed to AUI's efforts and initiatives to reduce UFG.

Compliance with Previous Commission Directions

In response to Decision 25747-D01-2020 regarding AUI's UFG riders for 2020-2021, AUI in this proceeding provided details regarding the causes of and fluctuations in UFG amounts. The data included data from June 2011 to May 2021, a separation of UFG by region, and the most significant causes of UFG. AUI also provided a description of actions taken to reduce UFG and UFG fluctuations and noted that this includes ongoing review and monitoring, AUI's system betterment program, meter testing, the retirement and replacement of assets known to contribute to UFG, continual support of damage prevention efforts, and continual improvement of processes that identify and reduce UFG. Further, it included a 2021 south region UFG audit report detailing audit activities that were undertaken to determine the nature of the positive gain of gas in the south region.

AUI provided regional analysis of UFG data separated into north, central and south regions from June 2020 to May 2021. It also described the causes of UFG and any corresponding identified issues by region. AUI reiterated that the exact quantification of most causes of UFG is impractical given the variable nature of known contributors.

The AUC found that AUI had complied with the directions issued in Decision 25747-D01-2021. AUI was found to have complied with all directions, and the AUC noted that the completed audit activities had ruled out most potential sources of the net gain of gas in the region, and no single problem or issue was found.

Conclusion

The AUC approved the applied for Rate Rider E and Rate Rider H. Consistent with previous decisions, AUI was directed in its next UFG application to, again:

- Develop and provide a relative ranking of UFG causes;
- Quantify the causes of UFG, where possible;

- Describe the specific actions taken by AUI to reduce UFG fluctuations, UFG gains, and UFG overall amounts;
- Provide reasons for any year-over-year changes in AUI's UFG;
- Update the historical data set, which spans the period for the most recent ten years of monthly data to the most current month for the receipt and delivery volumes and UFG percentage losses or gains; and
- Provide a regional UFG breakdown and any explanation and insight gained from the regional analysis.

***ATCO Electric Ltd. 2020-2022 General Tariff Application Compliance Filing,* AUC Decision 26477-D01-2021**
Compliance Filing - GTA

In this decision, the AUC set out its determinations on ATCO Electric Ltd.'s ("AE") compliance with the AUC's directions issued in Decision 24964-D01-2021 and Decision 24964-D02-2021.

AE's Compliance Filing

Direction 1 and Directions 3-12 issued in Decision 24964-D01-2021 concerned lease and operating rates; consistency in the shared services allocation formulas between proceedings 24964 and 25663; service allocator issues; the inclusion of deferral account adjustments in net revenues for the general cost allocator; the use of 2019 actual and 2020 forecast full-time equivalents ("FTEs") for GTA and general rate application ("GRA") test years; the reduction of the total pre-allocated pool of Indigenous, government relations and sustainability FTEs; the adjustment to shared services and capital FTEs; and the submission of assumptions and calculations of the shared services costs split between operations and maintenance ("O&M") and capital.

Direction 3, Decision 24694-D01-2021

Direction 3 required AE to use 2019 actual variables as inputs into the shared services allocation formulas. The AUC issued this direction to provide for consistency between proceedings 24964 and 25663.

In its compliance filing application, AE continued to incorporate 2018 actual variables. AE supported this calculation with its interpretation of Direction 3 and explained that using 2019 actual variables for 2021 and 2022 maintained consistency for the 2021 and 2022 test years that overlap with ATCO Pipelines' 2021-2023 GRA in Proceeding 25663.

The AUC disagreed with AE's interpretation of the direction and clarified that AE should not have restricted the use of 2019 actual variables to the 2021 and 2022 test years. Accordingly, to ensure compliance with Direction 3, AE was required to provide the AUC with revised documentation showing the incorporation of this direction and its effect on the revenue requirement. Accordingly, as a post-disposition filing, AE was required to submit documents incorporating the impact to its revenue requirement of reflecting the use of 2019 actual variables for the year 2020 for the purposes of allocated shared services costs.

Direction 1, 24964-D02-2021

In Direction 1, the AUC directed AE to use internal 2019 actual FTEs as the approved base level FTE complement for all test years. This base level of FTEs is a starting point for 2020 that will be adjusted following the AUC's findings on incremental FTEs proposed by AE in each of the test years.

The AUC found that AE had generally complied with this direction. It determined that whether AE's base level of FTEs (set at 2019 actual FTEs) should be adjusted to reflect the same quantum of FTEs used to inform its forecast revenue offset calculation was the outstanding issue.

The Consumers' Coalition of Alberta ("CCA") raised the issue that while the AUC did approve AE's revenue offsets, it was subject to and did not override the AUC's direction for AE to use its internal 2019 actual FTEs as the approved base level FTE complement for all test years. The CCA indicated that the AUC's direction required AE to update both its affiliate and non-affiliate FTEs, and accordingly, both its operating costs and revenue offsets.

In an information request ("IR") response, AE included scenarios addressing the CCA's concern. In one scenario, AE updates schedules that reflect revenue offsets based on incorporating its 2019 actual FTEs as the approved base level FTE complement for all test years. This scenario results in revenue requirement reductions of $5.140 million in 2020, $5.646 million in 2021, and $5.672 million in 2022. In a second scenario, AE reduced its non-affiliate O&M FTEs, while maintaining its affiliate FTEs for all test years. The impact to the revenue requirement based on this scenario is a reduction of $4.537 million in 2020, $4.964 million in 2021, and $4.986 million in 2022. AE submitted that the second scenario would better align with the AUC's approval of ATCO Electric Transmission's revenue offset forecast, notwithstanding AE's position that no adjustment was needed under either of the scenarios it addressed.

The AUC accepted the second scenario provided by AE. It found that the calculations reasonably reconcile the AUC's approval of AE's forecast revenue offset with the corresponding number of FTEs required to complete the work. Accordingly, AE was directed to file documents incorporating the impact to its revenue requirement of removing the 26.5 FTEs that it re-deployed from affiliate-related O&M activities to non-affiliate-related O&M activities (while maintaining affiliate O&M FTEs at 32.9), for the 2020-2022 test years, as discussed in the second scenario.

<u>Calculation of AE's Approved Revenue Requirement for the Years 2020-2022</u>

In a submission to Proceeding 26477, AE calculated its 2020-2022 revenue requirement adjustments related to its compliance with multiple directions issued in Decision 24964-D01-2021. This submission indicated revenue requirements of $698.639 million, $689.777 million, and $700.732 million for the years 2020, 2021, and 2022, respectively.

The AUC found that these adjustments did not reflect its findings with respect to AE's compliance with Direction 3 issued in Decision 24964-D01-2021. Accordingly, considering the reductions in the revenue requirements resulting from that direction, the AUC calculated revenue requirements of $698.058 million, $689.745 million, and $700.701 million in 2020, 2021, and 2022, respectively. AE was expected to reflect, in its post-disposition filing, the revenue requirements calculated by the AUC.

***ATCO Gas and Pipelines Ltd. 2021 Unaccounted-for Gas Rider D and Rider P,* AUC Decision 26776-D01-2021**

Gas - Rates

In this decision, the AUC approved the application from ATCO Gas North, a division of ATCO Gas and Pipelines ("ATCO"), to update the unaccounted-for gas ("UFG") Rider D and Rider P rates of 1.176 and 1.162 per cent, respectively.

In Decision 25798-D01-2020, the AUC had approved the Rider D rate for 2020-2021 of 1.01 per cent. Rider P is a new UFG rider charged to producer accounts.

<u>Background</u>

Charges for UFG are recovered from all shippers on the ATCO distribution system, including supply providers through Rider D. In Decision 26283-D01-2020, the AUC approved the implementation by ATCO of a new rate class to producer customers on a pilot basis. The AUC also approved the introduction of a new Rider P to collect UFG from producer accounts using ATCO's distribution system. This rider, with a rate equal to the approved UFG rate for delivery customers in 2020, will apply to producer volumes transacted off the distribution system and for which UFG would not be otherwise collected.

Discussion of Issues

Calculation of Rider D and Rider P

Consistent with previous applications, ATCO calculated its Rider D rate using receipt and delivery data from the preceding three years from the Daily Forecasting and Settlement System ("DFSS"). Using this data, specifically the percentage of deliveries, ATCO calculated an average of 1.176 percent to use as its 2021 Rider D.

As Rider P is applied to producer receipts, ATCO calculated the rider as a percentage of receipts from the three years preceding the application. Using this data, ATCO arrived at a UFG percentage of 1.162 as a proposed 2021 Rider P rate.

Compliance with Previous AUC Directions

The AUC had issued several directions to ATCO regarding Rider D. Most recently, Decision 25798-D01-2020 included directions to provide reasons for seasonal UFG differences and details regarding UFG fluctuations.

In respect of seasonal differences, ATCO submitted a general explanation, stating that calendarized monthly deliveries reported from the delivery points are calculated estimates and affect the accuracy of UFG on a monthly basis. Particularly during the shoulder season, unpredictable temperature fluctuations can result in fluctuations in meter accuracy.

In respect of UFG fluctuations, ATCO submitted that the seasonal operating plans, equipment failure, construction, pipeline leaks, hit lines, unsolicited use, and line heater fuel are the main issues causing increases or decreases of UFG.

In response to the AUC's request for information regarding steps taken by ATCO to reduce UFG, ATCO submitted that it continues to take various steps such as meter sizing procedures, seasonal operating plans, and collaboration between different divisions of ATCO Gas and Pipelines to ensure measurement accuracy in the expected flow conditions. Further, ATCO Gas and ATCO Pipelines work together cooperatively to identify and address UFG issues through upgrades in measurement equipment, data monitoring, verification of measurement data, seasonal operating adjustments, and adjusting sample points and heat areas.

Further, in response to the AUC's direction regarding the net results of the adjustment to UFG, ATCO submitted that the amount of total adjustment was 25 terajoules, or 0.01 percent, of total receipts. Data submitted by ATCO indicated that the carbon levy costs for 2019 and 2020 amounted to $286,223 and $415,864, respectively. The primary difference was indicated by the fact that no carbon levy was in effect from June until December 2019. Further, the carbon levy had changed from $1.517/GJ in 2019 to $1.050/GJ from January to March and $1.576/GJ from April to December 2020.

AUC Findings

The AUC reviewed the calculations submitted by ATCO and the responses to AUC directions regarding UFG. The AUC was satisfied that ATCO's proposed Rider D for UFG is within the historical range of UFG amounts, and for the purposes of this application, accepted ATCO's explanation that the increase is due to normal year-to-year fluctuations. ATCO is expected to continue filing future Rider D and Rider P applications jointly.

The AUC directed ATCO to continue to provide:

- Clear explanations of seasonal UFG differences, measurement corrections, and reasons for UFG increases or decreases;

- Details with respect to all measurement adjustments showing the reconciliation of prior years' data;

- Net results of the adjustments to UFG, both in terms of energy and as a percentage of receipts; and

- A table showing the monthly line heater fuel usage, the associated carbon levy dollars, and the difference from the previous year.

The AUC approved riders D and P at 1.176 per cent and 1.162 per cent, respectively, effective November 1, 2021.

***ATCO Gas and Pipelines Ltd. North Edmonton Loop Pipeline Project,* AUC Decision 26811-D01-2021**
Gas - Pipelines

In this decision, the AUC approved the application from ATCO Gas and Pipelines Ltd. ("ATCO") for an amendment to perform a line split, removal and resumption of segments of discontinued pipelines and to install two new pipeline segments under the existing License 2594 (the "Project").

Application

In its application, ATCO requested permission to remove sections and resume sections of the pipeline and to construct new sections. ATCO further applied to abandon two pipelines, which would be recorded in a subsequent application. ATCO submitted that the Project is part of the urban pipeline replacement program to ensure reliable gas to northeast Edmonton. The application was filed pursuant to Section 11 of the *Pipeline Ac*t and Section 4.1 of the *Gas Utilities Act,* and ATCO indicated that it complied with Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments, and Gas Utility Pipelines*.

Discussion and Findings

The AUC found that its decision would not directly or adversely affect the rights of a person. It further found that the participant involvement program had been conducted appropriately and that no public or industry concerns or objections remained.

The AUC accepted the assessment of the engineering assessment that indicated that the pipeline is suitable for resumption. It further accepted that the potential environmental impacts of the Project had been sufficiently addressed.

The AUC determined that approval of the application is in the public interest and is required to allow ATCO to connect the required high-pressure pipelines to ensure a reliable natural gas supply to northeast Edmonton. The application was approved as filed.

***BHE Rattlesnake GP Inc. Application for an Order Permitting the Sharing of Records Not Available to the Public Between BHE Canada Rattlesnake GP Inc., BHE Canada Rattlesnake L.P. and URICA Energy Real Time Ltd.,* AUC Decision 26838-D01-2021**
Market Oversight and Enforcement - FEOC

In this decision, the AUC granted the application from BHE Canada Rattlesnake GP Inc. ("BHEC") for an order permitting the sharing of records pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

Introduction and Procedural Background

BHEC filed an application seeking permission to share records not available to the public between BHEC, BHE Canada Rattlesnake LP ("BHEC LP"), and URICA Energy Real Time Ltd. ("URICA") relating to the 117.6 megawatt ("MW") Rattlesnake Ridge Wind Power Plant (the "Power Plant").

Subsection 3(3) of the *FEOC Regulation* authorizes the AUC to issue an order permitting the sharing of records on any terms and conditions that the AUC considers appropriate, provided that the records will not be used for any purpose that does not support the fair, efficient and openly competitive operation of the electricity market and that the sharing of records is reasonably necessary to carry out business. The AUC also takes market share control into account when making its determination.

The AUC was satisfied that BHEC had demonstrated that sharing the records with BHEC LP and URICA was reasonably necessary for BHEC to carry out its business as neither BHEC nor BHEC LP have the personnel or resources to accept energy or ancillary services dispatch orders on a 24-hour basis to manage the output of the power plant. It was also satisfied that the subject records would not be used for any purpose that did not support the fair, efficient and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation*. Relying on submissions from BHEC and written representations from BHEC and URICA, the AUC was satisfied that the parties would conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

The AUC further found that the total offer control figures of BHEC, BHEC LP and URICA were well below the maximum of 30 per cent, set out in Subsection 5(5) of the *FEOC Regulation*.

Given the Market Surveillance Administrator's ("MSA")'s mandate under Subsection 39(2)(a)(vi) of the *Alberta Utilities Commission Act*, the AUC considered the MSA's support of this application to have been a contributing factor in the decision to permit the sharing of records.

The AUC approved the application.

***Dunmore Solar Inc. Dunmore Solar Project,* AUC Decision 26485-D01-2021**

Solar Power

In this decision, the AUC approved applications from Dunmore Solar Inc. ("Dunmore") to construct and operate the Dunmore Solar Project (the "Project"). The Project consists of a 216-megawatt ("MW") solar power plant and the Dunmore 1011S Substation.

Applications

The Dunmore Solar Power Plant would consist of approximately 515,136 solar photovoltaic modules, each with a power rating of 500 watts, 82 inverter/transformer stations, each with a power rating of 2.5 megavolt amperes, an underground 34.5-kilovolt („kV") collector system, a fence and access roads. The final make and model of the components had not been finalized. The Dunmore Solar Power Plant would have a total generating capability of 216-MW for delivery to the Alberta Interconnected Electric System ("AIES"). The associated substation would increase the voltage from the collector voltage of 34.5 kV to the transmission system voltage of 138 kV. The Project is located on 623 acres of privately-owned land.

Dunmore stated that the interconnection point to the AIES would be to an existing AltaLink Management Ltd. ("AltaLink") transmission line. This interconnection would be subject to a future application from AltaLink.

Discussion and Findings

The AUC found that the application complied with the information requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. It further found that the participant involvement program met the requirements of Rule 007.

Regarding Indigenous consultation, the AUC was satisfied that Dunmore's consultation with the Blood Tribe, Piikani Nation and Siksika Nation, which raised no concerns, was appropriate.

The AUC found the environmental impacts of the Project to be acceptable, considering the risk assessment of Alberta Environment and Parks ("AEP") that indicated a low risk to wildlife and wildlife habitat posed by the Project.

AEP ranked the Project a high risk to wetlands. It noted that the Project would be constructed over six seasonal wetlands (Class III) and would not comply with the 100-meter setbacks for four seasonal (Class III) and one semi-permanent (Class IV) wetlands. The alternative mitigations proposed by Dunmore would not protect wetland habitat from permanent loss.

Dunmore committed to conducting sensitive amphibian surveys at all seasonal and semi-permanent wetlands prior to construction and notifying AEP of the results. AEP noted that Dunmore committed to several alternative mitigation methods during construction within the 100-meter wetland setbacks to minimize and eliminate the remaining risks.

Field studies completed by Dunmore indicated that it is unlikely that sensitive amphibians will use wetlands for breeding habitats that have been cultivated in the past.

At the time of the application, Dunmore had not submitted a renewable energy operations conservation and reclamation plan ("C&R Plan") as set out in AEP's *Conservation and Reclamation Directive for Renewable Energy Operations.* Dunmore committed to completing and submitting the final C&R Plan for the Project by September 20, 2021. The AUC imposed a corresponding condition of approval.

To further ensure the compliance of the Project with applicable rules and requirements, the AUC imposed multiple conditions of approval. Dunmore must submit a post-construction monitoring report as required by Rule 033. Further, to align assumptions of the application regarding glare, Dunmore is required to use an anti-reflective coating on the Project solar panels. Dunmore is also required to address issues related to glare that arise in a timely manner and file a report with the AUC detailing the issues that arose and how they were addressed no later than 13 months after the Project comes into operation. As Dunmore had not finalized its selection of equipment for the Project, the AUC also required that Dunmore file a letter once the selection is completed that confirms that the Project continues to abide by the applicable rules and that impacts of the Project remain within the values and levels approved in this decision.

<u>Decision</u>

The AUC determined that approval of the applications is in the public interest and approved the application to construct and operate the Dunmore Solar Project pursuant to sections 11, 14, 15 and 19 of the *Hydro and Electric Energy Act.*

***Enbridge Pipelines Inc. Application for an Order Permitting the Sharing of Records Not Available to the Public Between Enbridge Pipelines Inc., Tidal Energy Marketing Inc. and URICA Real Time Ltd.,* AUC Decision 26819-D01-2021**

Market Oversight and Enforcement - FEOC

In this decision, the AUC granted the application from Enbridge Pipelines Inc. ("Enbridge") for an order to permit the sharing of records pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

<u>Introduction and Procedural Background</u>

Enbridge filed an application seeking permission to share records not available to the public between Enbridge, Tidal Energy Marketing Inc. ("Tidal") and URICA Energy Real Time Ltd. ("URICA"), relating to the 20.01-megawatt (MW) South Edmonton Terminal Power Generation Facility (asset ID SET1).

In Order 26257-D02-2021, the AUC had approved the sharing of the non-public records in question between Enbridge and URICA. In this application, Enbridge submitted that the development and communication of price-quantity pairs in the energy and ancillary services markets to URICA would be most efficiently conducted through the involvement of both Enbridge and Tidal employees.

<u>AUC Findings</u>

Subsection 3(3) of the *FEOC Regulation* authorizes the AUC to issue an order permitting the sharing of records on any terms and conditions that the AUC considered appropriate, provided that certain requirements are satisfied. The AUC found that those requirements were met.

The AUC was satisfied that Enbridge had demonstrated that (i) the sharing of records with Tidal was reasonably necessary for Enbridge to carry out its business; and (ii) the subject records would not be used for any purpose that did not support the fair, efficient and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation*. Relying on submissions from Enbridge and written representations from Enbridge and Tidal, the AUC was satisfied that Enbridge and Tidal would conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

The AUC further found that total offer control of Enbridge, Tidal and URICA were well below the maximum of 30 per cent, set out in Subsection 5(5) of the *FEOC Regulation*.

Given the mandate of the Market Surveillance Administrator ("MSA") under Subsection 39(2)(a)(vi) of the *Alberta Utilities Commission Act*, the AUC considered the MSA's support of this application to have been a contributing factor in the decision to permit the sharing of records.

The AUC approved the application.

***EPCOR Energy Alberta GP Inc. 2021-2024 Energy Price Setting Plan,* AUC Decision 26316-D01-2021**
Regulated Rate Option – Energy Price Setting Plan

In this decision, the AUC considered the request from EPCOR Energy Alberta GP Inc. ("EPCOR") for approval of its 2021-2024 energy price setting plan ("EPSP"). The AUC denied all recommendations submitted by interveners and did not approve the EPSP and accompanying illustrative energy charge model as filed.

Improvements to Market Monitoring

EPCOR submitted that the data and analyses provided in the application demonstrate that the descending clock auctions conducted under its 2018-2021 EPSP generated substantial interest and participation from suppliers. EPCOR noted that the data confirms that the Alberta wholesale electricity market is sufficiently robust to facilitate strong competition in the descending clock auctions leading to competitive market prices.

The CCA submitted that EPCOR's application did not fully address whether the descending clock auctions under the 2018-2021 EPSP were competitive. It made a number of recommendations on what auction information should be monitored by EPCOR during the term of the 2021-2024 EPSP and reported in future applications. The Office of the Utilities Consumer Advocate ("UCA") submitted that there are a number of areas in which EPCOR's market monitoring could be improved, which would have provided more valuable insight into the competitiveness and operation of the 2018-2021 EPSP and its suitability for use going forward.The AUC rejected the recommendations and requests submitted by the CCA. The AUC found that the inclusion of information regarding auction participation levels in future application, as suggested by the CCA, was not proven to be beneficial and, if concerns about the competitiveness of the auctions were to arise, the Market Surveillance Administrator would initiate a review.

For the 2018-2021 EPSP period up to December 15, 2020, EPCOR provided information about the number of units of each energy product offered across all auction sessions by suppliers, with the suppliers broken down by their classification of physical suppliers or financial suppliers. It also reported the number of units of each energy product won by these suppliers. The CCA recommended that EPCOR be instructed to provide the disaggregated information as incentives for suppliers who have physical load positions separately from those who do not, may be different. The AUC denied this recommendation as there is now clear and convincing empirical evidence demonstrating that both suppliers with a physical position and suppliers with a purely financial position participate in the auction sessions and no benefit in filing the additional information has been demonstrated.

The CCA and UCA recommended that additional metrics be calculated and reported in order to assess the competitiveness of auction sessions.The AUC rejected the recommendation that EPCOR monitor and report five metrics for all three energy products (flat, peak, and full-load). Parties argued that using five metrics would allow for a better assessment of the competitiveness of the auctions, but no party raised significant concerns with the overall competitiveness of the auctions. In particular, no party submitted that EPCOR stop using the descending clock auctions because they are uncompetitive. The AUC therefore did not consider this suggestion related to auction competitiveness to be warranted.

EPCOR provided information about the number of bids that specified switches from one energy product to another. The AUC denied the recommendation that EPCOR monitor the nature and timing of switching behaviour. It found that the argument that the utility of the simultaneous procurement descending clock auction in large part depends on the auction eliciting significant switching behaviour. The AUC found that concerns regarding the low level of switching indicating that competition in the auctions may not be robust are not justified. Consequently, the AUC found it unnecessary for EPCOR to monitor the nature and timing of switching behaviour.

Proposed Amendments to the 2021-2024 EPSP

The proposed 2021-2024 EPSP included the flexibility for EPCOR to modify the calculation of the auction starting prices for the flat and peak energy products by adjusting the respective multipliers within a range of 1.15 to 1.25. The UCA, CCA and other interveners requested that the EPSP only be approved following certain amendments.

Interveners requested that EPCOR lower the ranges for the auction starting prices and that an alternate ending to the auctions be implemented "based on a threshold of excess capacity or a residual supply index. Once this threshold is reached, all remaining offers would declare a [*sic*] offer with offers paid as bid." The AUC denied both requests. It found that the suggestions were not well developed and that not all circumstances had been considered in the suggestion.

It was further requested that EPCOR revise the range and duration of the auction rounds from two to 15 minutes to a range of one to six minutes. The AUC again found that the submitted arguments supporting this suggestion were not sufficient to justify the amendments. The AUC considered that EPCOR would not jeopardize its interest in ensuring that its auctions are successful by arbitrarily changing the auction round length to discourage participation. The AUC also agreed with EPCOR that the flexible auction length of two to 15 minutes provided in EPCOR's 2021-2024 EPSP allows EPCOR to respond to participants requesting longer auctions and promoted regulatory efficiency.

The proposed 2021-2024 EPSP included a provision for EPCOR to modify the price decrement algorithm by adjusting the reduction factors within a range of values greater than 0.85 and less than or equal to 1. The AUC denied the recommendation that the flexibility of the price decrement algorithm be changed to allow a smaller range of 0.95 to 0.97. Again, the AUC found that the interveners did not provide sufficient evidence to justify changing the range from 0.85 to 1 to 0.95 to 0.97 and did not demonstrate a sufficient benefit to justify the change.

Term of the 2021-2024 EPSP and Generic Proceeding

EPCOR indicated that it intended to procure energy and calculate monthly energy charges under the 2021-2024 EPSP from May 1, 2021, until June 30, 2024.

Interveners submitted that EPCOR's proposal to continue using a descending clock auction is similar to the approach used by ENMAX Energy Corporation. Given the similarities, it was suggested that the timing of EPSP providers' applications, who have implemented or are intending to implement similar auctions, should be aligned. This was suggested to consider consolidating similar auctions with potential for administrative savings and benefits to competition. The UCA also submitted that there is considerable regulatory efficiency in aligning the timing of EPSP applications.

The UCA strongly recommended that the AUC initiate a generic proceeding well in advance of the expiry of the EPSPs. EPCOR argued that there are significant disadvantages with combining its auctions with other regulated rate option ("RRO") providers. It stated that these include increased costs because the most cost-effective approach for one provider may be different from another provider. EPCOR argued that the disadvantages outweigh any potential benefit.

The AUC denied both the recommendation to align expiry dates of the EPSP of the RRO providers or to establish a generic proceeding. It noted that there are at least four months between the approval of an EPSP and the first month under which monthly electric energy charges calculated under that EPSP are effective. Accordingly, aligning the expiry dates could lead to energy rates being calculated under one EPSP for less than 12 months, which does not support regulatory efficiency and would increase the regulatory burden.

The AUC found that other issues raised by the interveners would not be solved by aligning the proceedings or establishing a generic proceeding. The associated disadvantages would outweigh any benefit of implementing these recommendations. The AUC further repeated that interveners raised no serious concerns regarding the competitiveness of the auctions provided for in the 2018-2021 EPSP, which led the AUC to question how a generic proceeding would increase competition.

The AUC determined that the procurement method proposed by EPCOR for the 2021-2024 EPSP meets the requirement of RRO providers outlined in Section 4(1) of the *Regulated Rate Option Regulation.* Section 4(1) required RRO providers to, with reasonable transparency, use a fair, efficient and openly competitive acquisition process to ensure that the resulting prices for the supply of electric energy are just, reasonable, and electricity market-based.

Load Forecasting Model Separate from EPSP

Similar to the 2018-2021 EPSP, EPCOR's 2021-2024 EPSP includes a clause permitting EPCOR to file any improvement to its load forecasting method or significant changes to the inputs to that method, with the AUC for acknowledgment.

In response to an AUC question concerning changes of the clause from the one approved in the 2018-2021 EPSP, EPCOR stated that it could file the load forecasting method as a stand-alone document, incorporated by reference into the 2021-2024 EPSP. It would still be maintained and allowed to evolve separately. This could eliminate the need for EPCOR to refile the EPSP document after each change to the load forecasting method. The AUC agreed that filing the load forecasting methodology as a separate document is beneficial and directed EPCOR to revise its 2021-2024 EPSP by removing the load forecasting method and filing it as a stand-alone document.

Retention of a Backstop Supplier and Changes to the Illustrative Energy Charge Model

EPCOR was directed to file a newly executed backstop agreement once the successful backstop supplier was selected, for acknowledgment as a confidential post-disposition document. The filing must include a document that sets out any differences between the new and the executed backstop agreement in place for the 2018-2021 EPSP. The AUC also directed EPCOR to make specific changes to its originally filed illustrative energy charge model to correct an error and a manual entry oversight identified by EPCOR.

Natural Gas Exchange Monthly Auction Hosting Fee

The AUC accepted that EPCOR included the new Natural Gas Exchange ("NGX") flat monthly auction hosting fee of $12,500 per month as part of the NGX trading charges and transaction fees. The AUC also approved EPCOR's proposal to include up to four months of the new NGX monthly auction hosting fees as part of the energy charges for the first month under the 2021-2024 EPSP.

Procurement Conduct Agreement

The AUC accepted that EPCOR did not provide a procurement conduct agreement as part of its 2021-2024 EPSP for several reasons, including that it is unchanged from the agreement approved as part of the previous EPSP.

Monthly Energy Rate Reporting and Attestation Letter

EPCOR proposed submitting monthly acknowledgment filings consistent with the form and process approved for the monthly filings under previous EPSP, consisting of a forecast performance report, attestation letter, and the energy charge model.

The AUC found that the information that EPCOR proposed to file as part of the monthly filings for the energy charges determined following the 2021-2024 EPSP is substantially similar to what has been filed under the 2018-2021 EPSP. The AUC approved EPCOR's proposal to submit monthly acknowledgment filings.

***Irrigation Canal Power Co-operative Ltd. Barnwell Solar Project,* AUC Decision 26317-D01-2021**

Solar Power

In this decision, the AUC approved the application from Irrigation Canal Power Co-operative Ltd. ("IRRICAN") and qualified the 999-kilowatt ("kW") Barnwell Solar Project (the "Project") as a community generating unit.

Application

The Project would be located near the town of Taber, Alberta. IRRICAN submitted that the output capability would not exceed 999 kW but that the final number and model for the solar modules could change.

In that community benefits statement submitted in support of the application, IRRICAN estimated that the Project would generate a combined revenue of $3,625,000 over its 25-year life. It would also generate $7,900 in annual property tax revenues for the Municipality. With respect to environmental benefits, IRRICAN noted that the Project would repurpose unused land, as it will be located on an orphan well surface lease. The Project and the precedent it will set are also anticipated to create hope and self-sufficiency and increase social cohesion in the community.

FortisAlberta Inc. had qualified the Project as a small-scale generating unit under the *Small Scale Generating Regulation*. It also confirmed that it would be responsible for the metering costs, estimated to be $19.298.20.

AUC Findings

The AUC accepted that the Project is a small power plant within the meaning of Subsection 18(1) of the *Hydro and Electric Energy Regulation*. The AUC was also satisfied that the Project does not have adverse environmental impacts and complies with Rule 012: *Noise Control.* The AUC, accordingly, agreed that the Project is excluded from the application of sections 11 and 18 of the *Hydro and Electric Energy Act.*

The AUC determined that the application to designate the Project as a community generating unit satisfies the requirements of the *Small Scale Generating Regulation,* as it was submitted in the required form and included the required supporting documents and information.

Section 5 of the *Small Scale Generation Regulation* specifies the costs for which a small-scale power producer is responsible. Specifically, in the case of a community generating unit that is not within an isolated community, as is the case with IRRICAN's generating unit, subsection 5(2)(a) requires that the distribution owner purchase the meter that is installed for the community generating unit, to a maximum of one meter per facility. The AUC was therefore satisfied that FortisAlberta Inc. is entitled to recover the costs incurred to purchase the meter for the Project, pursuant to Subsection 5(2)(a) of the *Small Scale Generation Regulation*. Accordingly, as a condition of the qualification, IRRICAN is required to 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 within one month of the Project's in-service date.

AUC Decision

Pursuant to Section 3 of the *Small Scale Generating Regulation,* the AUC qualified the Barnwell Solar Project as a community generating unit.

***Pembina Pipeline Corporation Application for an Order Permitting the Sharing of Records Not Available to the Public Between Pembina Pipeline Corporation and URICA Real Time Energy Ltd.,* AUC Decision 26810-D01-2021**

Market Oversight and Enforcement - FEOC

In this decision, the AUC granted the application from Pembina Pipeline Corporation ("Pembina") for an order to permit the sharing of records pertaining to the electricity and ancillary services markets under Section 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

Introduction and Procedural Background

Pembina filed an application seeking permission to share records not available to the public between Pembina and URICA Energy Real Time Ltd. ("URICA"), relating to Pembina's pump stations in northwest Alberta, which have the capability to provide up to 15 megawatts (MW) of supplemental operating reserves. In their capacity to provide supplemental reserves, these pump stations operate under the Alberta Electric System Operator asset ID PPNW (Pembina pump stations).

Subsection 3(3) of the *FEOC Regulation* authorizes the AUC to issue an order permitting the sharing of records on any terms and conditions that the AUC considers appropriate, provided that certain requirements are satisfied. The AUC found that those requirements were met.

The AUC was satisfied that Pembina had demonstrated that the sharing of records with URICA was reasonably necessary for Enbridge to carry out its business and that the subject records would not be used for any purpose that did not support the fair, efficient and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation*. Relying on submissions from Pembina and written representations from Pembina and URICA, the AUC was satisfied that Pembina and URICA would conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

The AUC further found that the total offer control of Pembina and URICA was well below the maximum of 30 per cent, set out in Subsection 5(5) of the *FEOC Regulation*.

Given the Market Surveillance Administrator's ("MSA")'s mandate under Subsection 39(2)(a)(vi) of the *Alberta Utilities Commission Act*, the AUC considered the MSA's support of this application to have been a contributing factor in the decision to permit the sharing of records.

The AUC approved the application.