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

Benga Mining Limited v Alberta Energy Regulator, 2021 ABCA 363

Permission to Appeal – Respondent and Intervenor Status

In this decision, the Alberta Court of Appeal ("ABCA") considered applications from the Municipal District of Ranchland No. 66 (the "MD") and the Livingstone Landowners Group ("Livingstone") to be named respondents or intervenors in appeal applications brought by Benga Mining Limited ("Benga"), the Piikani Nation ("Piikani") and the Stoney Nakoda Nations ("Stoney Nakoda"). Each seeks permission to appeal the decision of the Joint Review Panel (the "Panel") for the Grassy Mountain Coal Project, denying Benga's application to construct and operate an open-pit coal mine in Southwest Alberta (the "Project"). The ABCA also considered the application from Mr. Allred, who supports the Project, to intervene.

The MD's application to be added as a respondent was granted. The applications of Livingstone and Mr. Allred were dismissed. The ABCA noted that should permission to appeal be granted to Benga, and without commenting on the merits of any such application, Livingstone may apply to intervene in that appeal.

<u>Background</u>

The Joint Review Panel denied Benga's application for a licence to construct and operate an open-pit metallurgical coal mine (the "Project") on June 17, 2021. The Project was held not to be in the public interest as it would result in significant adverse effects on the environment and the physical and cultural heritage of several Treaty 7 First Nations communities. These adverse effects were found to outweigh the low to moderate positive economic impacts on the regional economy.

Piikani indicated their support for the Project. Stoney Nakoda did not object to the Project. Both sought to appeal the Panel's decision arguing that it erred in law by failing to properly assess the public interest and by failing to further consult with the First Nations communities.

Benga asserted six errors of law or jurisdiction, including that the Joint Review Panel denied Benga procedural fairness, ignored relevant evidence, failed to consider rules of evidence, and failed to further consult with the First Nations communities.

<u>The MD's Application</u>

The MD is an entirely rural area. Most of the Project and the entire open-pit mine are located in the MD. The MD applied for standing, arguing that it has an environmental and economic interest.

The ABCA noted that it is recognized and confirmed by the Supreme Court of Canada that municipalities are, in a broad sense, a trustee of the environment. This is codified in s 3(a.1) of the *Municipal Government Act*. Because a legal interest may arise where the applicant has a statutory mandate to carry out its duties for the safety of the public, the ABCA determined that the MD has a legal interest in the outcome of the appeal.

Given its role in the original proceeding leading to the rejection of the Project, where the MD provided extensive evidence and arguments, and its broad public mandate, the ABCA determined that it was just and convenient to add the MD as a party.

The ABCA held that given the MD's statutory duties and purpose, the fact it represents the broad interests of its constituents, its high level of participation in the hearing, and the fact that the only respondent at the time of this decision was the AER, constituted extraordinary circumstances that warrant the MD being added as a respondent for the purpose of its participation in Benga's permission to appeal.

During the application, it became clear that the MD did not participate in any way on Indigenous issues. As a result, the ABCA held, it would not be just and convenient to allow it to participate in the permission to appeal applications of Piikani and Stoney Nakoda. The application to be named as a respondent to Benga's application was granted. The request to be added to the applications of Piikani and Stoney Nakoda was dismissed.

Livingstone's Application to be Named a Respondent

Livingstone is a non-profit organization that represents landowners and supporters in the Livingstone-Porcupine Hills area adjacent to the Project. Livingstone opposed the Project and was granted standing with full participation rights on the basis that "they have relevant information or expertise about the Project".

Livingstone did not articulate a legal interest aside from the fact that it was granted standing with full participation rights. Having relevant information does not constitute a legal interest. Livingstone did not demonstrate any proprietary or contractual interest or that its participation or addition as a respondent is needed to protect its interest. Livingstone did not demonstrate a legal interest, and its application to be added as a respondent was dismissed.

Livingstone and Mr. Allred's Application to be Named Intervenors

Mr. Allred is a resident of Blairmore, supports the Project and participated in the Joint Review Panel hearing and public engagement. The ABCA acknowledged that Mr. Allred is a concerned citizen prepared to volunteer his time and energy on the matter. However, exercising the rights as an engaged citizen at the first instance does not translate to a legal expectation of intervenor status. Similarly, the ABCA was not convinced that Livingstone would provide a unique perspective. Further, there was no indication that its interest in the proceedings would not be fully protected by the parties.

Conclusion

The MD's application to be added as a respondent was granted. The applications from Livingstone and Mr. Allred were dismissed as they did not demonstrate a legal interest in the outcome of the appeal.

ENMAX Energy Corporation v TransAlta Generation Partnership, 2021 ABCA 366

Recusal - Application for Rehearing

In this decision, the ABCA considered the appropriate procedure to be followed when an appellate judge recuses herself from the panel following the hearing of an appeal but before judgment is rendered. Although it found no legal reason for the panel to recuse themselves, it found that the only recourse available in circumstances where the remaining judges were not unanimous in their decision, was to order a rehearing of the appeal by a new panel.

Background

The appeals before the ABCA arose from a dispute over which party should bear financial responsibility for the failure of an electrical generating unit: see *ENMAX Energy Corp v TransAlta Generation Partnership*, 2019 ABQB 486. After the hearing but before the decision was issued, counsel for ENMAX Energy Corp. ("ENMAX") filed a letter raising the concern that the third judge appeared to be periodically inattentive during the hearing. On receipt of counsel's correspondence, that judge issued an apology to counsel and their clients and recused herself, having nothing to do with the appeals thereafter.

Application for a Rehearing

The ABCA found that during the hearing, neither counsel nor the other two judges on the panel were aware of the third judge's activity. Nevertheless, ENMAX argued that the other two judges on the panel are "tainted" by the inattention of the third judge. Neither the law nor the fully informed objective observer would support this proposition. The ABCA also emphasized that this is not a case of alleged bias.

ENMAX argued that the two remaining members of the panel needed to recuse themselves along with the unfocused judge and that the appeals needed to be reheard by three other judges. The ABCA determined that this was without merit. Because the remaining two judges were not aware of the third judge's inattention, they stand in the same position as the other members of the Court who are argued to be required to rehear the appeal.

Procedure Going Forward

ENMAX argued that the right to have an appeal decided by a full quorum of the Court is a substantive right, that it is entitled to an opportunity to persuade each of three judges to decide in its favour, and that any dissent in its favour might enhance an application for leave to appeal to the Supreme Court of Canada.

TransAlta Generation Partnership, as the respondent, argued that there is no reason to reargue the appeals and that the remaining members of the panel could render a decision. The presence of Section 8 in the *Court of Appeal Act* undermines any general proposition that there is a right to have an appeal decided by a full panel of three judges.

The ABCA held that on its proper interpretation, Section 8(e) of the *Court of Appeal Act* is clearly intended to be remedial. The ABCA noted that it would be impossible to list all of the circumstances under which one member of a panel might be unable to continue and when the incapacity might be discovered. The ABCA held that this section was designed to avoid unnecessary duplication of proceedings when that happens. Whether the event happens before or after the hearing, or whether it is only discovered later, does not change the remedial purpose of the section. The ABCA therefore held that the two remaining members of the panel “may” decide the appeals if they are unanimous. The decision of the remaining judges was, however, not unanimous. Accordingly, the only recourse available in the circumstances was to order a rehearing of the matter by a new panel.

ALBERTA ENERGY REGULATOR

***New Expedited Decisions Manual,* AER Bulletin 2021-43**
Expedited Decision Process

Since 2013, *Public Lands Act* applications administered by the AER were eligible for expedited decisions under the *Alberta Energy Regulator Rules of Practice*. As a result, the manual was managed by Alberta Environment and Parks, while the authority of expedited decisions was managed through the AER's *Rules of Practice*.

To combine the management of the manual and the expedited decisions, the AER *Rules of Practice* have been updated under Section 5.2(2)(b) of the AER *Rules of Practice*, introducing a new AER manual, Manual 022: *Expedited Decisions*. No changes have been made to the list of *Public Lands Act* applications that may be expedited, but the AER will now manage and publish the new manual.

Expedited applications do not have a set deadline to submit a statement of concern. The AER can make a decision at any point after an expedited application is submitted. These application types are outlined in Section 5.2.2 of the AER *Rules of Practice*.

***Invitation for Feedback on Revisions to Directive 050,* AER Bulletin 2021-044**
Applications - Regulatory Efficiency

The AER sought feedback on updates to Directive 050: *Drilling Waste Management*. The proposed changes reduce the regulatory burden throughout the life cycle of drilling waste management without compromising safety. The updates clarify the requirements, improve regulatory application efficiency, and enable operators to reduce land disturbance from drilling waste management practices.

***Request for Regulatory Appeal by Fort McMurray Métis Local Council 1935,* AER Request for Regulatory Appeal No. 1932350**
Regulatory Appeal - Consultation

In this decision, the AER considered the request from the Fort McMurray Métis Local Council 1935 ("McMurray Métis") for a regulatory appeal of the decision to issue the Horizon South Lease 24 ("Horizon South") approvals to Canadian Natural Resources Limited ("CNRL"). The AER decided that McMurray Métis was not directly and adversely affected and, consequently, dismissed the request for a Regulatory Appeal.

<u>McMurray Métis' Request for Regulatory Appeal</u>

McMurray Métis' filed its request for regulatory appeal on the following basis:

1. The AER misapprehended the information provided by McMurray Métis and, as a result, made conclusions that were not supported by the facts.
2. The AER misapplied the test established by the Court of Appeal in *Dene Tha' First Nation v. Alberta (Energy and Utilities Board),* (2005) ABCA 68*,* by finding that more evidence was required for the AER to find that the McMurray Métis were directly and adversely affected.
3. The AER did not fulfill its public interest mandate by discarding the clear issue that McMurray Métis have Aboriginal rights that may be impacted and have not been considered in the approval process.

First Ground

McMurray Métis disagreed with the finding of the AER that they are not directly and adversely affected by the application solely based on the fact that the applications relate to lands that are within Métis' harvesting area without providing further factual connection evidence.

McMurray Métis stated that the statement of concern ("SOC") submitted provided additional factual information in support of the direct and adverse effect on the McMurray Métis. This included 94 Indigenous Knowledge and Use ("IKU") intersections, including the categories of hunting, fishing, transportation, Indigenous knowledge, and access. McMurray Métis submitted that their SOC includes the required factual connection in accordance with the *Kelly vs. Alberta (Energy Resources Conservation Board)*, 2009 ABCA 349 (Kelly No. 1), *Kelly vs. Alberta (Energy Resources Conservation Board)*, 2011 ABCA 325 (Kelly No. 2) and *Kelly vs. Alberta (Energy Resources Conservation Board)*, 2012 ABCA 19 (Kelly No. 3).

Second Ground

The AER's decision to dismiss the SOC was based on the understanding that the impacts of the Horizon Oil Sands Mine and Processing Plant and Joslyn North Mine Oil Sands Project projects on the McMurray Métis have been assessed through previous project approvals and that because the Horizon South integration project will have a smaller footprint, impacts will be minimized. McMurray Métis argued that these findings overlook the fact that concerns have never been before any decision maker since McMurray Métis have never been engaged by CNRL or Total E&P Canada Limited. As a result, no traditional land use information was gathered in respect of the project areas, and no Indigenous knowledge information was included in any of the applications, which in turn means that none of the McMurray Métis concerns in the SOC have been addressed.

Third Ground

The AER found that it does not have jurisdiction to assess Crown consultation and that the Aboriginal Consultation Office determined that no consultation was required. McMurray Métis were of the view that the AER has a public interest mandate and that Directive 056*: Energy Development Applications and Schedules* requires the proponent to engage with affected parties.

McMurray Métis advised the AER that consultation had not taken place, and the AER interpreted this concern as a request for compensation. This was not a request for compensation, and, in McMurray Métis view, it is clearly within the AER jurisdiction to ensure that the proponent has assessed the impact to Indigenous people who have rights to harvest in the project area when making a decision in the public interest.

<u>Reasons for Decision</u>

The AER noted that the Supreme Court of Canada has held, regarding prior consultation, the claimant must show a causal relationship between the decision in question and a potential adverse impact on the Aboriginal rights. The direct and adverse effect must be as a result of the decision in question and, prior and continuing breaches will only trigger a duty to consult if the decision under consideration has the potential of causing a novel impact on an existing right.

As a result, the scope of this regulatory appeal is limited to assessing the direct and adverse effects on McMurray Métis that are the result of the approvals under appeal.

The AER found that McMurray Métis have not provided sufficient evidence to establish the required degree of location or connection between the proposed project and the impacts on their rights in the vicinity of the project. Because the integration project does not involve a new project, new activities, or disturbance of any additional lands, it does not create an additional risk for direct and adverse effects by the decision.

The AER found that McMurray Métis are not directly and adversely affected by the decision and dismissed the request for regulatory appeal.

ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator 2022 Balancing Pool Consumer Allocation Rider F Application, AUC Decision 26979-D01-2021

ISO Rates - Balancing Pool - Rider F

In this decision, the AUC approved the application from the Alberta Electric System Operator ("AESO") of its 2022 Balancing Pool consumer allocation Rider F. The AUC approved the proposed Rider F of $2.20 per megawatt-hour ("MWh").

Pursuant to Section 82 of the *Electric Utilities Act* ("*EUA*"), the Balancing Pool, a corporation established by Section 75 of the *EUA,* must prepare a budget for each fiscal year setting out its estimated revenues and expenses. Based on the forecast revenues and expenses in its budget, the Balancing Pool must determine an annualized amount that will be refunded to (or collected from) electricity market participants over the year. Following receipt of the Balancing Pool's annualized amount that will be collected from or refunded to electricity market participants, the AESO is required to include this amount in its tariff.

The AUC approved the Balancing Pool's request for a consumer charge of $2.20/MWh in the 2022 calendar year, as filed. The AESO's proposed Rider F would levy this charge to all Rate Demand Transmission Service and Rate Demand Opportunity Service market participants, except for the City of Medicine Hat or BC Hydro at Fort Nelson, British Columbia.

Alberta Electric System Operator Application for Approval of Proposed Amended Section 103.3 of the ISO Rules, AUC Decision 26908-D01-2021

Market - Financial Security

In this decision, the AUC approved the application from the Alberta Electric System Operator ("AESO") for approval of amendments to Section 103.3 *Financial Security Requirements* of the independent system operator ("ISO") rules.

Proposed Changes

Section 103.3 applies to electricity market participants with financial obligations to the ISO and sets out requirements for the provision and acceptable forms of financial security, determination of financial obligations, the use of unsecured credit, and ISO review and reassessment of market participants' financial security.

The AESO proposed amendments that will expand its flexibility to respond to market participants' financial situations, increase its authority to mitigate risk, and clarify and streamline provisions to align with the red tape reduction initiative.

After considering an ISO rule, in accordance with subsection 20.21(1) of the *Electric Utilities Act* ("EUA"), the AUC may approve the ISO rule, direct the AESO to revise the ISO rule or refuse to approve the ISO rule. Section 20.9 of the *EUA* requires the AUC to make rules requiring the AESO to consult with parties in the development of ISO rules and permits the AUC to develop rules governing the AESO's process in the development of those rules. *Rule 017: Procedures and Process for Development of ISO Rules and Filing of ISO Rules with the Alberta Utilities Commission* ("*Rule 017*"), is the AUC rule which was created in response to Section 20.9 of the *EUA*.

Main Issues

Do the Rule Amendments Meet the Criteria set out in the EUA?

The AESO filed its application pursuant to Section 20.21 of the *EUA.* The AUC was satisfied, based on the AESO's explanations, that the proposed amendments to Section 103.3 are not technically deficient; support the fair, efficient and openly competitive operation of the market to which they relate; and are in the public interest, as required by Subsection 20.21(2) of the *EUA*.

Did the AESO Fulfill Its Obligation, Under Rule 017, to Adequately Consult With Stakeholders?

The AESO issued a letter of notice to stakeholders in March 2021 and revised Rule 103.3 in response to all comments provided by stakeholders.

The AESO submitted that stakeholders were concerned that the provision allowing the AESO to request any financial information is too broad in scope. In response, the AESO explained that it usually only requests recent financial statements. However, it requires the ability to request additional relevant information to properly assess the ongoing creditworthiness and financial security requirements of market participants.

The second issue raised by stakeholders in the consultation process was that the acceptable form of financial security should be extended to insurance bonds from investment-grade rated entities. The AESO submitted that it has an obligation to settle the wholesale electricity market. As a result, it needs forms of financial security that can be reliably and efficiently converted into cash. The AESO does not consider insurance bonds to be of sufficient liquidity and reliability and excluded insurance bonds from previous versions of Section 103.3 as well.

The AUC was satisfied that the requirements regarding information and consultation established in *Rule 017* have been met. The process followed by the AUC provided enough opportunity for stakeholders to make submissions and raise concerns.

Order

In proposing the amendments to Section 103.3, the AESO met the requirements to Section 20.21 of the *EUA* and *Rule 017*. Pursuant to Subsection 20.21(1)(a) of the *EUA,* the AUC approved the proposed amended Section 103.3 of the ISO rules*, Financial Security Requirements*.

***AltaLink Management Ltd. 2022 Interim Transmission Facility Owner Tariff,* AUC Decision 26947-D01-2021**
Interim Rates - TFO Tariff

In this decision, the AUC approved a 2022 interim transmission facility owner ("TFO") tariff for AltaLink Management Ltd. ("AML") of $56,736,664 effective January 1, 2022 on an interim refundable basis.

Background and Application

In Proceeding 26509, AML's 2022-2023 transmission general tariff application ("GTA"), AML requested approval of a forecast 2022 revenue requirement of $811,456,637 for 2022 or a net 2022 monthly transmission tariff of $67,621,386. AML added that the requested interim monthly tariff amount of $67,621,386 for 2022 represents a reduction of $3,065,310 or 4.3 percent of the final approved 2021 tariff amount approved in Decision 25870-D01-2020, before the AUC approved an additional refund of accumulated depreciation in Decision 26248-D01-2021. In this application, AML requested approval of interim rates as it did not have an order permitting the continuation of its tariff in 2022.

In evaluating interim rate applications, the AUC applies its two-part test. This test first evaluates the quantum and need factors, and in the second step considers the public interest in the approval of the interim rates.

The approval of AML's requested interim rates satisfied the quantum and need factors addressed in the first step of the test. Subject to findings of Proceeding 26509 regarding AML's 2022-2023 GTA, the projected monthly revenue deficiency of $21,769,444 for 2022 is material and probable. The AUC however noted that several contentious issues still needed to be addressed through Proceeding 26509. AML's request to recover 100 percent of its 2022 revenue shortfall is unreasonable as it would include revenue amounts associated with those contentious items. The AUC therefore approved the collection of 50 percent of the identified shortfall. This amount would preserve AML's financial integrity by avoiding a material revenue shortfall between the existing 2021 monthly tariff and the forecast 2022 monthly revenue requirement.

The AUC determined that the interim adjustment will promote rate stability and ease rate shock and help maintain intergenerational equity and provide appropriate price signals. As a result, the AUC found that public interest factors considered in the second step of its test were also satisfied.

Decision

The AUC approved AML's 2022 interim monthly TFO tariff in the amount of $56,736,664 effective January 1, 2022, on an interim basis. The AUC further ordered that the existing terms and conditions of AML's TFO tariff will remain in effect until a further order or decision from the AUC is issued.

As the rate increase is requested on an interim basis, it will be trued up when AML's final 2022-2023 transmission revenue requirements are approved.

***ATCO Gas and Pipelines Ltd. Gleichen Branch Transmission Pipeline Loop Installation,* AUC Decision 26938-D01-2021**
Facilities - Gas

In this decision, the AUC approved the application from ATCO Gas and Pipelines Ltd. ("ATCO") to construct approximately 2.68 kilometers of new 88.9-millimeter outside-diameter, high-pressure sweet natural gas pipeline to loop the existing 60.3-millimeter Gleichen Branch Transmission Pipeline under Licence 1819 (the "Project").

Application

ATCO submitted that the Project is required to meet the current and future natural gas demands on the Gleichen-Cluny transmission system. The need was demonstrated in the approved 2021-2023 General Rate Application ("GRA").

The Project cost is estimated to be $1,600,000. ATCO is responsible for 100 percent of the cost. ATCO noted that the cost exceeded the costs approved in the GRA proceeding. It noted that the increase is due to an increase in the length of the loop on the 60.3-millimeter Gleichen Branch Transmission Pipeline from 2.4 kilometers to 2.68 kilometers, which allows for a tie-in to the existing steel pipeline that is more easily constructible than an aluminum pipeline tie-in. In addition, the longer pipeline allows the existing pipeline to remain in service during the tie-in, thereby minimizing customer impact during construction. ATCO submitted that even with the additional cost, the Project remained the least cost alternative.

Findings

Considering that the Project need has been established in the ATCO 2021-2023 GRA, and as there were no outstanding environmental or public interest concerns, the AUC found that approval of the Project is in the public interest as required by Section 17 of the *Alberta Utilities Commission Act*. The AUC determined that the minor increase in Project length to facilitate a tie-in to the existing steel pipeline rather than the existing aluminum pipeline is operationally prudent.

Decision

Pursuant to Section 11 of the *Pipeline Act* and Section 4.1 of the *Gas Utilities Act*, the AUC approved the application.

***ATCO Electric Ltd. Decision on Preliminary Question Application for Review and Variance of Decision 26477-D01-2021,* AUC Decision 26895-D01-2021**
R&V - Rates

In this decision, the AUC denied an application by ATCO Electric Ltd. ("AE") to review and vary Decision 26477-D01-2021 (the "Compliance Decision"), a decision on the compliance filing for its 2019 general tariff application.

<u>Discussion</u>

AE submitted its application for review and variance ("R&V"), arguing that the AUC made errors of fact, or mixed fact and law with respect to the calculation of labour costs and the corresponding number of approved full-time equivalents ("FTEs").

The GTA Decision

In its 2019 general tariff application, AE applied for approval of its revenue requirement for the 2020-2022 test period, Decision 24964-D02-2021 (the "GTA Decision"). The first part of the GTA Decision relevant to this review application is the findings and directions of the panel for the general tariff application (the "GTA panel") with respect to FTEs.

In the GTA Decision, the GTA panel found that AE did not justify its claimed need for most of the additional applied-for FTEs, compared to its 2019 actual FTE complement. AE was directed to use its internal 2019 actual FTEs as the approved base level FTE complement for the 2020-2022 test years. Further, the GTA panel approved AE's applied-for forecast revenue offset.

The Compliance Decision

In the Compliance Decision, the AUC examined whether AE used the internal 2019 actual FTEs as directed. In response, AE submitted that it had reclassified specific FTEs. In 2019, AE had 59.4 FTEs that provided operations and maintenance ("O&M") services to affiliates and outside parties on an actual basis. In its compliance filing, AE submitted a base FTE complement that included 32.9 affiliate and outside party O&M FTEs instead of 59.4. As a result, AE's revenue requirements were only being offset by 32.9 affiliate and outside party O&M FTEs instead of 59.4.

The compliance panel noted that the GTA Decision did not approve a reallocation or "re-deployment" of 26.5 FTEs from affiliate O&M work to non-affiliate O&M work for this test period as submitted by AE.

The Review Application

AE relied on Section 5(1)(a) of Rule 016 (Review of Commission Decisions) as the grounds for its application and also broadly alleges that the manner in which the compliance decision was made was procedurally unfair. The onus of demonstrating the existence of an error under Rule 016 lies with the applicant. The AUC may grant an application for review if it determines the applicant has demonstrated that the AUC "made an error of fact, or mixed fact and law where the legal principle is not readily extricable, which is material to the decision and exists on a balance of probabilities."

The AUC noted that AE did not identify if the alleged errors are errors of fact or mixed fact and law, or whether its procedural fairness argument forms the basis for all three. As procedural error is no longer within the scope of Rule 016, the AUC dismissed the application to the extent that it was based on allegations regarding procedural fairness. The review panel commented that a general reference to all types of errors is not helpful.

(a) Alleged error 1: the compliance panel rendered decisions that seek to overturn, reverse and alter decisions rendered in the underlying decision.

The AUC interpreted AE's submissions to argue that the cumulative result of the GTA Decision was that the total FTEs for the test period would be higher than 2019 actuals, but the result of the compliance decision is that the total FTEs approved for the test period is lower than 2019 actuals. As a result, the compliance decision would reverse and conflict with the base decision. If this was the case, AE argued that it could not have known that the AUC would render inconsistent decisions and therefore did not have an opportunity to address this outcome.

The AUC did not accept that the compliance decision reverses the GTA Decision. AE had an opportunity to address the potential interdependency of the GTA Decision directions based on which it conducted the FTE reallocation in its information response, its argument, and its reply argument in the compliance proceeding. AE had and used this opportunity but failed to convince the AUC of its position.

(b) Alleged error 2: the compliance panel relied on a purported interdependency of decisions when none was established, shown to be necessary or proved to exist.

AE took issue with the basis for the compliance panel's finding that AE's compliance filing did not accurately reflect the implementation of Direction 1 of Decision 24964-D02-2021. It challenged the compliance panel's assessment of the interdependent nature of Direction 1 – establishing the base level for FTEs – and AE's forecast revenue offset calculation and associated affiliate FTEs.

The AUC noted that AE's revenue offsets track the costs of resources that are used to provide services to affiliates and outside parties. It found that these revenue offsets are, by their nature, linked to FTEs. The AUC determined that the compliance panel's interpretation of the GTA Decision meant that all directions of that decision are subject to all findings and other directions made elsewhere. Further, finding that the original compliance filing did not accurately reflect the implementation of the directions as it pertains to revenue offsets did not constitute an error.

(c) Alleged error 3: the compliance panel rendered decisions unsupported by the evidence and contrary to the evidence on the record.

AE argued that the Compliance Decision resulted in AE having 26 fewer FTEs than its total 2019 actual FTE complement. The AUC found it unclear what error AE was alleging with this statement. Regardless, the AUC determined that there was no basis for the claim that the decrease was inconsistent with or reversed the original GTA Decision.

The review panel observed that the base FTE complement approved in the compliance decision was consistent with AE's actual 2019 FTE complement when affiliate/services to outside party FTEs are offset against AE's total FTEs. If the compliance panel approved the FTE complement that ATCO Electric originally filed in its compliance filing, the result would have been that AE would have 26.5 more FTEs providing transmission utility O&M services than it did in 2019.

This would have been an error. AE can only recover the costs from ratepayers of FTEs that provide services to the regulated transmission utility. This would have been inconsistent with the GTA panel's original decision that, subject to a select number of FTE additions and reallocations, AE had not justified that it needed more FTEs, relative to its 2019 actual FTE complement, to provide services to Alberta customers in the 2020 – 2022 period. The review panel determined that it was within the compliance panel's purview to interpret the directions in the GTA Decision to give effect to what was clearly the intent of the original findings, and the compliance panel was in the best position to do so, having been on the original GTA panel.

The AUC held that AE failed to demonstrate that the compliance panel made an error, whether of fact or mixed fact and law.

<u>Decision</u>

AE's application for review and variance was dismissed.

Brooks Solar II GP Inc. Brooks Solar II Project Community Generation Designation, **AUC Decision 26661-D04-2021**

Community Generating Units

In this decision, the AUC approved the application from Brooks Solar II GP Inc. ("Brooks Solar") to qualify the Brooks Solar II Power Plant (the "Power Plant"), located in the County of Newell, as two community generating units.

Background

The AUC approved the application to construct and operate the Power Plant in Decision 26661-D02-2021. In this decision, the AUC considered Brooks Solar's request to qualify the Power Plant as two community generating units pursuant to the *Small Scale Generation Regulation.*

The distribution facility owner, FortisAlberta Inc. ("FortisAB"), confirmed that it had qualified the Power Plant as two small-scale generating units under the *Small Scale Generation Regulation*. FortisAB stated that it would be responsible for the metering of the Power Plant should the AUC approve the community generating unit application. The metering costs total approximately $60,000, including $10,000 in installation fees per meter.

AUC Findings

The AUC noted that Section 3 of the *Small Scale Generation Regulation* allows a small-scale power producer, who owns a small-scale generating unit that is the subject of a community benefits agreement, to apply to the AUC to have the small-scale generating unit qualified as a community generating unit. The AUC further noted that Section 3 requires that the application include the community benefits agreement or community benefits statement that applies to the small-scale generating unit.

Upon receipt of an application, the AUC determines whether the small-scale generating unit qualifies as a community generating unit. If it does qualify, the AUC determines the compensation the distribution owner should receive in relation to the costs to purchase the meter installed for the community generating unit, as described in either Subsection 5(2)(a) or 5(3)(a)(i) of the *Small Scale Generation Regulation*.

The application from Brooks Solar met the qualifying requirements and the AUC therefore designated the Power Plant as a community generating unit under the *Small Scale Generation Regulation*.

The Power Plant has two distinct interconnection points and therefore consists of two separate facilities within the meaning of the *Small Scale Generation Regulation*. Each facility has been qualified as a small-scale generating unit, has a distinct Alberta Electric System Operator asset ID, and requires its own meter.

The AUC recognized that a power plant may consist of multiple generating units and that, in some circumstances, depending on the interconnection configuration, each of these generating units may constitute its own facility as defined in the *Small Scale Generation Regulation*. The AUC however noted that while the *Small Scale Generation Regulation* permits such facilities to be qualified as separate community generating units, the AUC is also cognizant of the potential for large projects to be severed into multiple facilities, thereby increasing reimbursable meter costs, without any corresponding increase in benefits to the community. Accordingly, where a small-scale power producer requests that multiple facilities be qualified as community generating units, the AUC will exercise careful scrutiny of the nature and extent of the benefits to be conferred on the associated community group, to ensure that the qualification is in the public interest.

The AUC was satisfied that in this specific case, the Power Plant constitutes two separate facilities as defined in Subsection 1(h) of the *Small Scale Generation Regulation*. Although both facilities are subject to a single community benefits agreement, the benefits contemplated therein include a commitment to provide significant funding on an ongoing basis to facilitate environmental education within local schools, as well as to support existing social and economic welfare initiatives.

The AUC qualified the Power Plant as two community generating units under the *Small Scale Generation Regulation*.

As the distribution facility owner, FortisAB is entitled to recover the costs incurred to purchase the meters for the project (estimated to be $40,000), pursuant to Subsection 5(2)(a) of the *Small Scale Generation Regulation*. The AUC imposed the following condition to the qualification of the project as two community generating units under the *Small Scale Generation Regulation*:

Once the distribution owner has purchased the meters for the community generating units, within one month of the project's in-service date, Brooks Solar II GP Inc. must provide the AUC with written confirmation of the actual cost to purchase the meters.

Decision

The AUC qualified the Power Plant as two community generating units.

***ENMAX Energy Corporation 2020 Non-Energy COVID-19 Deferral Account,* AUC Decision 26505-D01-2021**
Rates - Utility Payment Deferral Program

In this decision, the AUC approved an application from ENMAX Energy Corporation ("ENMAX") for a 2020 non-energy COVID-19 deferral account. A deferral account balance of $1.268 million was approved for collection between December 1, 2021, to May 31, 2022, through a rate rider in the amount of 0.0468 per site per day for residential and commercial classes.

Background

The 2020 final non-energy rates approved by the AUC for ENMAX on July 16, 2020, did not include any forecast costs arising from the COVID-9 pandemic. ENMAX applied to set up a non-energy deferral account to recover the incremental costs it incurred between June 19, 2020, and December 31, 2020, because of the COVID-19 pandemic and to collect the balance in that deferral account.

Generally, if the AUC approves rates as final, they are not subject to future revisions, except for limited circumstances, such as an appeal of the final rates. Regulated rate option ("RRO") providers may apply for deferral accounts as part of a non-energy rate application when there is difficulty in establishing a reasonable forecast for items such as expenses and revenue. If a deferral account is approved, the non-energy rates are not approved as final rates because the balance in the deferral account will have to be settled at a later date. ENMAX did not request a non-energy COVID-19 deferral account for 2020 in its 2017-2020 non-energy application as the pandemic had not yet arrived.

Issues

Should ENMAX be Permitted to Establish a 2020 Non-Energy COVID-19 Deferral Account

Applications for deferral accounts as part of a non-energy rate application require that the applicant shows that there is difficulty in establishing a reasonable forecast for items such as expenses and revenue. If a deferral account is approved, it is not known if the balance will be collected from or refunded to customers. The AUC has the authority to approve cost recovery through a deferral account pursuant to Section 6 of the *Regulated Rate Option Regulation*. Section 6 also sets out that any cost or expense approved by the AUC to be recovered by the RRO provider must be prudent and reasonable.

The AUC determined that the COVID-19 pandemic and the related uncertainty and difficulty in forecasting pandemic-related costs justified deviation from traditional deferral account criteria. The pandemic itself, the state of emergency declared by the Government of Alberta on March 17, 2020, and the severe economic downturn that resulted are all factors that could not have been reasonably known or forecast by ENMAX when it submitted its 2017-2020 non-energy application in 2018.

In considering the fairness of ENMAX's request for the deferral account, the AUC noted that ENMAX, as an RRO provider, must provide service to customers who cannot contract with competitive retailers. As a result, the RRO's ability to adapt to market forces and adjust its fees is limited. Because of the pandemic, ENMAX incurred RRO costs in excess of one million dollars in 2020, and its only mechanism to recover costs is through AUC-approved rates.

The AUC approved the 2020 COVID-19 deferral account for the period June 19, 2020, to December 31, 2020.

The AUC noted that the *Utility Payment Deferral Program Act* was enacted on May 12, 2020, allowing the deferral of customers' utility bill payments, as well as financial support to regulated rate providers and other regulated and competitive entities so these service providers would have money to pay, for example, distributors. The AUC found that the utility payment deferral program ("UPDP") rate rider should reflect the unpaid amounts from March 18 to June 18, 2020. To address the gap between June 19 and July 15, 2020, and the inability of RRO providers to recover COVID-19 related costs for that period, the AUC revised the start date to June 19, 2020, stating: "Amending the date to June 19, 2020, for the COVID-19 deferral account will allow for the reasonable recovery of cost impacts that were not associated with the deferral period under the UPDP".

The July 28, 2021 ruling, setting June 19, 2020, as the commencement of the COVID-19 deferral account, was not challenged by ENMAX. Exceptions to the rule against retroactive ratemaking were commented on in detail in Decision 790-D02-2015, including the exceptions of deferral accounts and the knowledge exception. The AUC determined that there was no error in applying the knowledge exception here. The knowledge exception refers to circumstances where parties to the rate proceeding know (or ought to know) that rates were subject to change, at first instance to July 16, 2020, and then to June 19, 2020, after the UPDP decision was issued.

The AUC determined that a contrary direction would result in either ENMAX or its customers having no means of adjusting for COVID-19 pandemic-related costs not included in UPDP costs between June 19 and July 15, 2020.

Should the AUC Approve the Balance in the Deferral Account and the Associated Rate Rider?

ENMAX calculated and reported the balance in the deferral account as $1.240 million. The most significant applied-for elements are a collection of $1.071 million from customers for bad debt and a refund of $57,000 to customers for billing and customer care.

(a) Balance in the Deferral Account

The AUC did not approve administrative costs of $46,000 requested by ENMAX. It found that it could not approve this cost category as there was no specific approved forecast for the administrative costs. Regarding the incremental bad debt expense, an issue regarding the nature of bad debt arose. The question the AUC sought to answer was: when could a bill sent to a customer be written off as uncollectible?

ENMAX submitted that the bad debt expense is not incurred when electricity is consumed when a bill is issued nor when payment is due. This is because ENMAX does not know whether the bill will be paid at those times. It incurs the bad debt expense when a bill remains unpaid 60 days after payment is due. The AUC found this explanation for the calculation of its bad debt expense reasonable and appropriate. It is the difference between the actual bad debt expense and the forecast bad debt expense. The AUC approved the balance of $1.071 million for the bad debt expense deferral.

The Utilities Consumer Advocate ("UCA") took issue with the costs associated with billing and customer care ("B&CC"). The actual B&CC costs for 2020 were $0.40 million less than the forecast, but only $0.056 million of the $0.40 million is attributable to the deferral account period. The UCA stated that this was simply a matter of shifting costs from earlier in the year to later in the year. It argued that if ENMAX is allowed to rely on the cost amounts shifted to later in the year to offset the savings that would otherwise accrue to customers through the deferral account, this would result in double counting.

The AUC found that the UCA failed to demonstrate how there was double counting. The AUC agreed with submissions from ENMAX that the incurred B&CC costs, in this case, involved a timing issue, neither ENMAX nor the UCA can change when the costs are incurred. The time at which costs are incurred determines if the costs are eligible for deferral account treatment.

The AUC was concerned with a discrepancy in the actual B&CC costs for 2018. The AUC could not trace the $8,992,609 ENMAX used as the actual B&CC costs for 2018 to the $8,883,000 approved in a previous decision. ENMAX's use of $8,992,609 instead of $8,883,000 resulted in a lower refund amount for the B&CC cost deferral account and a corresponding higher amount in the overall deferral account to be collected from ENMAX's RRO customers. The AUC used the $8,883,000 previously approved and approved a refund of B&CC costs in the amount of $74,000.

The AUC approved a total deferral account balance of $1.268 million.

(b) Rate Rider Period and Associated Rate Rider Amount

The AUC determined that a six-month period of the rate rider is acceptable, as suggested by the UCA. From December 1, 2021, until May 31, 2022, the AUC approved a rate rider of 0.0468 per site per day for the residential rate class and the commercial rate class.

***ENMAX Power Corporation Type 1 Capital Tracker - Green Light Rail Transit Project*, AUC Decision 26589-D01-2021**

Capital Tracker - Required by Third Party

In this decision, the AUC denied the application from ENMAX Power Corporation ("EPC") for a Type 1 capital treatment of funds associated with the relocation of EPC's infrastructure and service connection work pursuant to The City of Calgary's ("Calgary") Green Line Light Rail Transit ("LRT") Project (the "Project").

Consequently, the AUC directed that EPC refund all associated placeholder amounts previously collected from customers in a compliance filing to this proceeding.

Background and Procedural Summary

The PBR Framework

As part of the framework of the performance-based regulation ("PBR") plans, the AUC separated capital funding into two categories: Type 1 and Type 2 capital. Type 1 capital is intended to provide supplemental funding to a distribution utility for a type of capital that the utility has not deployed in the past. It is supplemental because it is in addition to the funding (or revenue) the distribution utility receives under the other terms of the PBR plan, including Type 2 capital. Under the PBR plans, a distribution utility may apply for an adjustment to account for the effect of exogenous and material events for which it has no other reasonable cost recovery or refund mechanism within the PBR plan (Z Factor).

EPC's Type 1 Capital Tracker Application

In 2018, Calgary reached an agreement with the federal and provincial governments to fund the first stage of the Project. As the owner of the electric distribution system in Calgary, EPC is required to perform service connection work for the planned LRT expansion. EPC is required to relocate existing civil and electrical infrastructure to accommodate the proposed LRT alignment. EPC filed the application for supplemental Type 1 capital funding for these expenditures.

In its 2019 annual PBR rate adjustment filing, EPC stated that it had received a request from Calgary to relocate existing infrastructure and was granted approval of a Type 1 capital funding placeholder equal to 90 percent of the management-approved internal forecast costs associated with the relocation.

In this application, EPC requested a true-up of its 2019 and 2020 Type 1 capital funding placeholder and associated revenue requirements.

While the AUC determined that the Project meets the Type 1 capital tracker materiality threshold, it found that the Project cannot be characterized as extraordinary and finds that the expenditures incurred by EPC under the Green Line Project are types that can reasonably be considered as having been previously included in EPC rate base.

Issues

Materiality Threshold and Criterion 2 - Required by a Third Party

The materiality threshold for Type 1 capital tracker funding is calculated annually as the dollar amount equal to four basis points of the utility's return on equity. The AUC found that the Project met the Type 1 capital tracker materiality threshold in 2019, 2020, 2021 and 2022. EPC incurred capital additions in 2019 and 2020 and requested approval of the Type 1 capital tracker funding for its revenue requirement of $0.48 million in 2019 and $1.15 million in 2020.

Criterion 2 provides that a project must be required by a third party. The AUC considers that there are two questions within this criterion: (i) what entity is requiring the Project to be completed? And (ii) is that entity a third party?

Regarding the first question, the AUC determined that it was undisputed that EPC's Green Line Project is required and that it is Calgary, EPC's sole shareholder, that is requiring EPC to complete the Project.

The assessment of whether Calgary is a third party, as required by the second question, is complicated because Calgary is EPC's sole shareholder. EPC and Calgary have a relationship beyond that of a utility and a municipality.

EPC argued that it was relevant in which capacity Calgary acted and that, in these circumstances, Calgary acted in its capacity as a municipality when making decisions regarding the planning and construction of the Green Line LRT extension. The Utilities Consumer Advocate ("UCA") argued that the term third party requires a narrow interpretation and that third party must be more than just a separate legal entity. The UCA argued that Calgary plays a role in the governance of EPC and receives a financial benefit from EPC in the form of dividends. As a result, Calgary and EPC are closely connected and cannot be considered arm's length.

While Calgary has some control over EPC through the election of EPC's board of directors and review of EPC's business plans, the AUC determined that Calgary's interactions with EPC go beyond the corporate relationship. Depending on the circumstances, Calgary may or may not be considered a third party in the context of Criterion 2 when making a request of EPC. In considering Criterion 1, the AUC agreed with EPC that it needs to consider the extent to which a request by Calgary is made in its capacity as a municipality versus as EPC's shareholder.

Within the Green Line LRT Project context, the AUC determined that Calgary acted in its capacity as a municipality. The AUC found that EPC's Green Line Project can be considered to be required by a third party. Accordingly, this Project meets Criterion 2 for the Type 1 capital tracker treatment.

Criterion 1 - Extraordinary and Not Previously Included in Rate Base

Criterion 1 requires that a project must be extraordinary and not previously included in the distribution utility's rate base.

EPC argued that the Project is unique as it had not undertaken a project of comparable size or complexity before. EPC supported the extraordinary nature of the Green Line Project by pointing to the magnitude of capital additions, unparalleled project complexity, line length, iterative design process, and unique land use and planning considerations.

The UCA and Consumers Coalition of Alberta argued that EPC had not described that the Project meets the requirements of Criterion 1. It noted that a "project must be of a *type* that is extraordinary" and that EPC had not made it clear that this is the case.

The AUC determined that this Project did not create issues that EPC had not faced before and that the challenges were not unusually complex. The AUC noted that the Project is different from previously undertaken projects but is not beyond EPC's normal course of business.

The AUC determined that neither the Green Line Project nor any segment meets Criterion 1 for the Type 1 capital tracker treatment.

Conclusion

EPC had been authorized to collect the placeholder amounts of $1.0345 million, $1.2546 million, and $1.78 million for 2019, 2020 and 2021, respectively for the Project from its customers. As the AUC found that the Project does not meet the requirements of Criterion 1, EPC was directed to refund all Green Line Project Type 1 capital tracker placeholder amounts to customers in 2022 by way of a compliance filing.

EPCOR Distribution & Transmission Inc. 2022 System Access Service Phase 2 Application, **AUC Decision 26836-D01-2021**
Rates - AESO Tariff

In this decision, the AUC approved the application from EPCOR Distribution & Transmission Inc. ("EDTI") to modify its 2022 system access service ("SAS") rate design. The modification includes a monthly non-coincident peak ("NCP") metered demand charge for several EDTI's commercial and industrial customer rate classes.

Introduction

EDTI pays for the costs it incurs in operating its electric distribution business, as well as the costs and charges imposed on it for accessing the electric transmission system with revenue obtained from its distribution tariff. Through the distribution tariff, EDTI charges each customer class for service and terms and conditions of service.

In this Phase 2 application, EDTI, as the utility, apportions its annual revenue requirement approved in Phase 1 among its customers. Generally, Phase 2 is broken up into two steps. First, the utility allocates the costs to various customer rate classes. Then it uses those cost allocations to inform how to design customers' rates.

EDTI confirmed that its proposal to include an NCP demand charge would not change the total revenue it collects.

Discussion of Issues

Why Should an NCP Demand Charge be Included in EDTI's Rate Design?

EDTI applied to include the NCP demand charge to address inequity resulting from the individual tariffs of the Alberta Electric System Operator ("AESO") and EDTI.

EDTI submitted that the proposed rate design is more equitable as customers with low NCP demand in a given month will experience lower charges. This is consistent with the corresponding lower AESO demand transmission service ("DTS") bulk system costs. Customers with higher NCP demand in a given month will experience higher charges consistent with higher corresponding AESO DTS bulk system costs.

The AUC determined that the proposed changes to the SAS rate design contribute to aligning EDTI's rate design for the transmission costs portion of its distribution tariff with the AESO's rate design. This contributed to passing on the AESO's intended price signals accurately to the end-use customers.

How Will the Customers be Impacted by an NCP Demand Charge?

EDTI explained that for months when a customer's NCP demand equals its billing demand, its SAS charges will increase slightly under the new rate structure. On the other hand, in months where a customer's NCP demand is low compared to its billing demand, its SAS charges will decrease under the new rate structure. If a customer's peak demand varies from month to month, their bills during months of low demand will decrease.

An analysis of bill impacts submitted by EDTI indicated that the bill impacts that most customers would likely experience are between +2.5 and -2.5 percent. The AUC determined that these impacts would be acceptable. The AUC noted that some customers would likely experience bill decreases of more than 10 percent. However, as EDTI's proposed rate design was found to create more equitable rates overall, the AUC found these exceptions to be acceptable.

When Should this Change be Implemented?

At the time of this application, the AUC was still reviewing a proposal from the AESO to update its bulk and regional tariff rate design in Proceeding 26911. The result of Proceeding 26911 could provide a change in the AESO's rates which could impact EDTI's SAS rate design further.

EDTI explained that it chose to move forward with this application despite the effects of Proceeding 26911 for several reasons. This included an attempt to reduce potential rate shock for customers that are being transferred to EDTI's rates because of a change in service provider after the City of Edmonton's annexation of land and the subsequent transfer of service territory. EDTI also explained that it had been working on filing this application based on directions to include an NCP demand charge in the rate design made to FortisAlberta Inc. by the AUC in Decision 2014-018 but paused during the AESO's consultations on its bulk and regional tariff rate design. When EDTI learned that the AESO's preferred tariff structure continued to include a coincident peak demand charge, EDTI resumed preparing its application to adjust its own rate design.

The AUC noted that pending Proceeding 26911, EDTI's SAS rate design might need to be reassessed to ensure its alignment with the AESO tariff. However, EDTI's proposed timing to implement the rate design changes strikes a balance between addressing the immediate bill impacts resulting from annexation, improving alignment with the current AESO tariff, and being mindful of instability in customer bills that might occur if the AESO's bulk and regional tariff design is adjusted as currently proposed.

The AUC approved EDTI's applied-for changes to the SAS rate design but has determined a compliance filing is necessary for EDTI to incorporate the most recent available information in its calculated SAS rates. In its annual performance-based regulation rate adjustment filing, EDTI applied for its SAS rates that will be effective on January 1, 2022. On November 18, 2021, EDTI updated those SAS rates to reflect the DTS rates and Balancing Pool consumer allocation rider applied for by the AESO. The SAS rates applied for in this proceeding, which EDTI proposed to be effective April 1, 2022, did not incorporate these updates. EDTI was directed to submit a compliance filing containing updated SAS rates, supporting calculations, and EDTI's standard bill impact analysis, on or before February 15, 2022.

EDTI was also directed to review how its billing minimums are set for its capacity charge for each rate class and to propose changes as necessary in its next Phase 2 application.

<u>Order</u>

The AUC approved the application and ordered EDTI to file a compliance filing to its 2022 SAS Phase 2 application by February 15, 2022.

Horseshoe Power GP Ltd. Application for an Order Permitting the Records Not Available to the Public Between Horseshoe Power GP Ltd., Horseshoe Power Limited Partnership and URICA Energy Real Time Ltd., **AUC Decision 26941-D01-2021**
Market Oversight and Enforcement - FEOC

In this decision, the AUC approved the application from Horseshoe Power GP Ltd. ("Horseshoe") 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>

Horseshoe filed an application seeking permission to share records not available to the public between Horseshoe, Horseshoe Power Limited Partnership ("Horseshoe LP") and URICA Energy Real Time Ltd. relating to the 6.05 megawatt Blackfalds Power Generation Facility (asset ID BFD1), located in the County of Lacombe.

AUC Findings

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 Horseshoe had demonstrated that (i) the sharing of records with URICA was reasonably necessary for Horseshoe 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 Horseshoe and written representations from Horseshoe LP and URICA, the AUC was satisfied that Horseshoe 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 total offer control percentages of Horseshoe, Horseshoe LP, and URICA were well below the maximum of 30 percent, 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.

Horus Solar Alberta Kirckaldy Solar Energy Centre, **AUC Decision 26395-D01-2021**

Facilities - Solar Power

In this decision, the AUC approved the applications from Horus Solar Alberta Ltd. ("Horus") to construct and operate the 350-megawatt ("MW") Kirkcaldy solar power plant (the "Power Plant") and the Kirkcaldy 1009S Substation (the "Project"). The Project will have a total footprint of 206 hectares and be located on privately owned land near Vulcan, Alberta.

Application and Project Details

The Power Plant will consist of approximately 638,610 solar photovoltaic modules, a fixed-tilt and ground-mounted racking system, 140 inverters of 3.15-megavolt ampere capacity, a 34.5-kilovolt ("kV") underground collector system, fence, and access roads. The Power Plant will deliver the electricity to the Alberta Interconnected Electric System.

At the time of this decision, Horus was working with the Alberta Electric System Operator to optimize the interconnection of the Project. The interconnection of the Project would be subject to future applications.

AUC Findings and Decision

The AUC determined 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 also found that the participant involvement program submitted with the application met the requirements of Rule 007.

The renewable energy referral report ("referral report") obtained from Alberta Environment and Parks ("AEP") indicated that the Project would be located partially on tame grassland functioning as a habitat for grassland breeding birds, including species at risk. Despite commitments made by Horus, AEP noted that there would be an increased risk to breeding birds during construction. Horus submitted that if it is required to conduct construction activities in the restricted activity period between April 15 and August 15, it will conduct nest sweeps within 100 meters of tame grassland, and if nests or nesting behaviour are detected, a species-specific setback (minimum 100 meters) will be applied until the young fledge and the nest has been confirmed inactive by an experienced wildlife biologist.

The AUC acknowledged that the Project could negatively impact breeding birds on tame grasslands but found that the commitments made by Horus to decrease the mortality risk was reasonable in the circumstances.

In accordance with Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants,* the AUC imposed as a condition that Horus submit to AEP and the AUC annual post-construction monitoring survey reports.

As the predictions of the solar glare assessment submitted by Horus assumed that anti-reflective coating would be used on the solar panels, the AUC imposed the use of such reflective coating as a condition of approval. Further, Horus is required to file a report with the AUC detailing complaints, concerns, and how Horus addressed these during the first year of operation.

At the time of this decision, Horus had not finalized the selection of equipment and the layout of the Project. The AUC required that, at least 90 days prior to beginning construction, Horus files a final Project update confirming the selection of equipment and layout and that the Project has stayed within the allowances for solar power plants.

Subject to the conditions imposed by the AUC and in accordance with Section 17 of the *Alberta Utilities Commission Act*, the AUC determined that approval of the project is in the public interest having regard to the social, economic, and other effects of the project, including its effect on the environment.

***Jenner 2 GP Inc. and Jenner 3 GP Inc. Jenner 2 and Jenner 3 Wind Power Projects,* AUC Decision 22866-D01-2021**

Wind - Facilities

In this decision, the AUC approved the applications from Jenner Wind LP, through its two subsidiaries, Jenner 2 Limited Partnership and Jenner 3 Limited Partnership ("Jenner"), to construct and operate the Jenner Wind Power Project 2 (the "Jenner 2 Plant") and Jenner Wind Power Project 3 (the "Jenner 3 Plant") power plants, and to connect the power plants to the Alberta Interconnected Electric System (the "Projects").

Applications and Proceeding Processing History

On August 8, 2017, Jenner, applied to construct and operate a 180-megawatt ("MW") wind power plant, designated as the Jenner Wind Power Plant Expansion. The proceeding was placed in abeyance in January 2018 to allow the applicant to consult with stakeholders who had submitted statements of intent to participate. Following consultation, in March 2020, an amendment to the Jenner Wind Power Plant Expansion project application was filed that would create two discrete projects: the Jenner 2 Project, consisting of 17 turbines with a total capability of 71.4 MW, and the Jenner 3 Project, composed of 26 turbines for a capability of 109.2 MW.

In June of 2020, the AUC ruled that the Projects, as applied for, were not in the public interest because the Projects posed substantial, unacceptable environmental risks that were not adequately mitigated by the proposed mitigation and monitoring plans. The AUC put the applications in abeyance to allow Jenner an opportunity to explore ways to avoid or further reduce the potential and residual effects of the projects on wildlife and wildlife habitat.

The Amended Applications

Jenner amended the applications, proposing fewer turbines with a higher individual capability for the same total capability. The Projects will now use turbines with a hub height of 114 meters and a rotor diameter of 160 meters. The nameplate capacity of each turbine is 5.56 MW, but the individual output of each turbine would be controlled via a Wind Farm Management System.

The amended applications included the reports and assessments required for wind power project applications by Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* ("Rule 007").

Discussion

The renewable energy referral reports from Alberta Environment and Parks ("AEP") for the Projects submitted together with the March 2020 amendments originally concluded that the Projects pose an overall high risk to wildlife and wildlife habitat. Issues identified by AEP included the Projects' location on native grassland and the high occurrence of species at risk, including numerous sensitive grassland-dependent species and the proposed installation of overhead collector lines.

Jenner updated the Projects to reduce the potential effects on wildlife and wildlife habitat and submitted the Projects' update reports to AEP for reassessment. On March 8, 2021, AEP issued separate referral report amendment letters for the Projects and determined that the revised layout generally met the intent of AEP policy and the *Wildlife Directive for Alberta Wind Projects.*

The amendment included the removal of turbines that would have been sited on native grasslands. Further, AEP noted that the layout had been changed to reduce the effect on native grassland. While the Projects would align with the directive, the risk of avian mortality would remain high because of the abundance of breeding birds and species at risk in the Projects.

AEP determined that there also remained a risk to amphibian species at risk and ground-nesting raptor species affected by the Projects. However, AEP determined that the changes to the layout of the Projects decreased the risk to wildlife and wildlife habitat. AEP's Renewable Energy Referral Report concluded that the updated Projects posed a moderate risk to wildlife and wildlife habitat.

The *Historical Resources Act* approval issued to Jenner requires three stone features of archeological importance in the Jenner 3 Project area to be flagged or fenced to ensure avoidance. A fourth requires no further action as long as the site is avoided. A historic structure was also noted that must be avoided during all development activities.

Findings

The AUC considered the applications under sections 11, 14, 15, 18 and 19 of the *Hydro and Electric Energy Act.* The AUC determined that the applications met the information requirements of Rule 007.

Regarding the remaining risk to wildlife and wildlife habitat determined by AEP, the AUC found that implementing mitigation measures and imposing conditions to minimize residual effects on native grassland and the potential for direct impacts to wildlife and wildlife habitat is of high importance in this instance. As a condition of approval for both Projects, the AUC required that:

(a) The approval holder shall not perform any construction activities within areas of tame and native grassland during the restricted activity period for breeding birds of April 1 to July 15 as described in the *Wildlife Directive for Alberta Wind Energy Projects.*

The AUC was satisfied that the remaining risk will be adequately mitigated through the mitigation measures proposed and committed to by Jenner.

As required by Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants,* the AUC also issued as a condition of approval that:

(b) The approval holder shall submit a post-construction monitoring survey report to AEP and the AUC within 13 months of the Jenner 2 [Jenner 3] wind project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys, pursuant to Subsection 3(3) of Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*.

Decision

Pursuant to Sections 11 and 18 of the *Hydro and Electric Energy Act*, the AUC approved the applications.

***SWITCH Power Corporation and 2079816 Alberta Ltd. Joffre Solar Project Phase 1 and 2,* AUC Decision 26733-D01-2021**

Solar Power - Facilities

In this decision, the AUC approved an application from SWITCH Power Corporation ("SWITCH") and its general partner, 2079816 Alberta Ltd., to construct and operate the 22-megawatt Joffre Solar Project Phase 1 and the 25-megawatt Joffre Solar Project Phase 2 (the "Projects"). The AUC also approved the connection of the power plants to the FortisAlberta Inc. distribution system. The Projects will be constructed on 290 acres of privately owned land in Lacombe County, Alberta.

Application

SWITCH's application included a participant involvement program and a noise impact assessment that raised no issues. The solar glare assessment indicated that the Projects pose a low potential for hazardous glare conditions along the roads and dwellings assessed. The application also included a *Historical Resources Act* approval, a renewable energy referral report issued by Alberta Environment and Parks Fish and Wildlife Stewardship ("AEP") and a renewable energy project submission report. These reports concluded that the Projects would cause a low risk to wildlife and wildlife habitat and that any potential adverse effect of the Projects can be effectively mitigated.

Findings

The AUC was satisfied that the application met the applicable information requirements and that a participant involvement program was conducted in accordance with Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*.

SWITCH had not finalized the selection of equipment for the Projects, and the AUC imposed the following as a condition of approval:

(a) Once SWITCH has made its final selection of equipment for the Projects, it must file a letter with the AUC that identifies the make, model, and quantity of the equipment and, if the equipment layout has changed, provide an updated site plan. This letter must also confirm that the finalized design of the Project will not increase the land, noise, glare or environmental impacts beyond the levels approved in this decision. This letter is to be filed no later than one month before construction is scheduled to begin.

The solar glare assessment predicted that four dwellings near the Projects, Township Road 384, and the intersection of Township Road 384 and Range Road 260 will experience up to 10,225 minutes of yellow glare from the Projects.

The solar glare assessment noted that barriers such as trees, shrubs and buildings that exist between the Projects and the dwellings would significantly reduce or eliminate glare impacts on the dwellings. If further mitigation is required, additional vegetative screening could be planted. Green Cat Renewables Inc. conducted the assessment and added that Township Road 384 is not expected to experience high traffic volumes, and as such, the glare on the road and at the intersection is unlikely to cause adverse effects. It concluded that, overall, the Projects pose a low potential for hazardous glare conditions along the road routes and dwellings assessed.

The AUC noted its expectation that SWITCH will address any glare issues associated with the Project in a timely manner. In addition to the condition noted above, the AUC imposed the following conditions of approval:

(b) SWITCH shall use an anti-reflective coating on the solar panels of the Projects, as indicated in the solar glare assessment.

(c) SWITCH shall file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the Projects during its first year of operation, as well as SWITCH's response to the complaints or concerns. SWITCH shall file this report no later than 13 months after the project becomes operational.

The AUC, relying on the finding of the renewable energy referral report and the renewable energy project submission report and notes, the fact that the Projects would be located entirely on previously disturbed land and that the location aligns with the *Wildlife Directive for Alberta Solar Projects*, determined that the potential environmental effects of the project are limited and can be reasonably mitigated to an acceptable level. SWITCH is expected to adhere to and implement all mitigation measures included in those reports.

As it had not yet been submitted, the AUC required that SWITCH file a stand-alone, project-specific environmental protection plan and the Project's initial renewable energy operations conservation and reclamation plan, no later than one month before construction is scheduled to begin.

Finally, as required by Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*, the AUC imposed, as a condition of approval, that SWITCH submits an annual post-construction monitoring survey report to Alberta Environment and Parks ("AEP") and the AUC within 13 months of the Project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys.

Decision

The AUC considered the applications to be in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act* and approved the applications pursuant to Sections 11 and 18 of the *Hydro and Electric Energy Act.*

***SWITCH Power Corporation and 2079816 Alberta Ltd. Youngstown Solar Project,* AUC Decision 26734-D01-2021**

Solar Power - Facilities

In this decision, the AUC approved an application from SWITCH Power Corporation ("SWITCH") and its general partner, 2079816 Alberta Ltd., to construct and operate the 6.0-megawatt Youngstown Solar Power Plant (the "Power Plant") and to connect the Power Plant to the ATCO Electric Ltd. distribution system (the "Project"). The Project will be constructed on 40 acres of privately owned land between Scotfield and Cereal, Alberta.

Application

SWITCH's application included a participant involvement program, a noise impact assessment, and a solar glare assessment that raised no issues. The application also included a *Historical Resources Act* approval, a renewable energy referral report issued by Alberta Environment and Parks Fish and Wildlife Stewardship ("AEP") and an environmental evaluation report. These reports concluded that the Project would cause a low risk to wildlife and wildlife habitat and that any potential adverse effect can be effectively mitigated.

Findings

The AUC was satisfied that the application met the applicable information requirements and that a participant involvement program met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*.

The AUC noted its expectation that SWITCH will address any glare issues associated with the Project in a timely manner. In addition to the condition noted above, the AUC imposed the following conditions of approval:

(a) SWITCH shall use an anti-reflective coating on the Project solar panels, as indicated in the solar glare assessment.

(b) SWITCH shall file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the project during its first year of operation, as well as SWITCH's response to the complaints or concerns. SWITCH shall file this report no later than 13 months after the project becomes operational.

The AUC, relying on the finding of the renewable energy referral report and the renewable energy project submission report and noting as well that the Project is sited entirely on previously disturbed land and the siting of the project aligns with the *Wildlife Directive for Alberta Solar Projects*, determined that the potential environmental effects of the Project are limited and can be reasonably mitigated to an acceptable level. SWITCH is expected to adhere to and implement all mitigation measures included in those reports.

As it had not yet been submitted, the AUC required that SWITCH file a stand-alone, project-specific environmental protection plan and the Project's initial renewable energy operations conservation and reclamation plan, no later than one month before construction is scheduled to begin.

SWITCH had not finalized the selection of equipment for the Project, and the AUC imposed the following as a condition of approval:

(c) Once SWITCH has made its final selection of equipment for the Project, it must file a letter with the AUC that identifies the make, model, and quantity of the equipment and, if the equipment layout has changed, provide an updated site plan. This letter must also confirm that the finalized design of the Project will not increase the land, noise, glare or environmental impacts beyond the levels approved in this decision. This letter is to be filed no later than one month before construction is scheduled to begin.

Finally, as the Project is a solar project, it is subject to Rule 033*: Post-approval Monitoring Requirements for Wind and Solar Power Plants*, the AUC imposed, as a condition of approval, that SWITCH 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 subsequent year for which AEP requires surveys.

Decision

The AUC considered the applications to be in the public interest in accordance with Section 17 of *the Alberta Utilities Commission Act* and approved the applications pursuant to Sections 11 and 18 of the *Hydro and Electric Energy Act*.

***Versorium Energy Ltd. Benalto 1 Distributed Energy Resource Power Plant,* AUC Decision 26919-D01-2021**
Facilities - Natural Gas

In this decision, the AUC approved the applications from Versorium Energy Ltd. ("Versorium") to construct and operate the 5.044 megawatt ("MW") natural gas-fired power plant (the "Power Plant") near Sylvan Lake. The AUC also approved the application to interconnect the Power Plant to the FortisAlberta Inc. electric distribution system.

Application

The Power Plant includes natural gas-fired reciprocating engines, a switchgear building, a generator step-up transformer, a low-pressure natural gas pipeline to connect to the Burnt Lake Gas Co-op natural gas system, and a distribution line to connect the Power Plant to the distribution system.

AUC Findings and Decision

The AUC reviewed the information filed with the application, including a noise impact assessment, participant involvement program, air quality assessment report, and environmental evaluation report. The AUC found that these submissions included all information required under Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments, and Gas Utility Pipelines* and Rule 012: *Noise Control.*

The application indicated that all regulations will be abided by and that all emission objectives will be met. The project was further found to meet the requirements for a connection order.

The AUC determined that the applications are in the public interest under Section 17 of the *Alberta Utilities Commission Act.* Pursuant to Section 11 and Section 18 of the *Hydro and Electric Energy Act,* the AUC approved the applications to construct and operate and to interconnect the Power Plant.

***Versorium Energy Ltd. Briker 1 Distributed Energy Resource Power Plant and Interconnection,* AUC Decision 26841-D01-2021**

Facilities - Natural Gas

In this decision, the AUC approved the applications from Versorium Energy Ltd. ("Versorium") to construct and operate the 5.0 megawatt ("MW") natural gas-fired power plant (the "Power Plant") near Paradise Valley. The AUC also approved the application to interconnect the Power Plant to the ATCO Electric Ltd. electric distribution system.

Application

The Power Plant includes 2.522 MW natural gas-fired reciprocating engines, a switchgear building, a generator step-up transformer, a low-pressure natural gas pipeline to connect to the County of Vermilion River's natural gas system, and an approximately 100-meter-long distribution line to connect the Power Plant to the distribution system.

AUC Findings and Decision

The AUC reviewed the information filed with the application, including a noise impact assessment, participant involvement program, air quality assessment report, and environmental evaluation report. The AUC found that these submissions included all information required under Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments, and Gas Utility Pipelines* and Rule 012: *Noise Control.*

The application indicated that all regulations will be abided by and that all emission objectives will be met. The project was further found to meet the requirements for a connection order.

The AUC determined that the applications are in the public interest under Section 17 of the *Alberta Utilities Commission Act.* Pursuant to Section 11 and Section 18 of the *Hydro and Electric Energy Act,* the AUC approved the applications to construct and operate and to interconnect the Power Plant.

CANADA ENERGY REGULATOR

Enbridge Pipelines Inc. Application for Canadian Mainline Contracting, CER Reasons for Decision RH-001-2020

Firm Service - Access to Capacity

In this decision, the CER denied the application from Enbridge Pipelines Inc. ("Enbridge") to introduce firm service on the Canadian Mainline.

The CER found that the application would cause a foundational shift in Canada's oil pipeline system by virtue of its temporal and volumetric scope. It could singlehandedly move the transportation of oil by pipeline in Canada from predominantly uncommitted service to mostly committed capacity.

The CER noted that many of Enbridge's submissions had merit and that the application provided a strong justification for some firm service on the Canadian Mainline. However, the request from Enbridge to remove 90 percent of uncommitted capacity for periods of up to 20 years would have dramatically and suddenly changed and likely diminished overall access to the Canadian Mainline without a compelling justification. This could risk significant disruptions to the market without a reliable way to respond.

The CER concluded that Mainline contracting does not comply with Subsection 239(1) of the *Canadian Energy Regulator Act* ("*CER Act*") and raises concerns in respect of sections 230 and 235 of the *CER Act*.

<u>Common Carriage Obligation</u>

Enbridge applied for firm service on 90 percent of the available capacity of the Canadian Mainline. Enbridge also requested a declaration that its proposed Open Season Procedures are appropriate and will lead to an open season that is fair, transparent, and consistent with Enbridge's obligations pursuant to Section 239 of the *CER Act.* Section 239 describes the common carriage obligation.

The CER determined that to meet the common carriage obligation while offering firm service, an oil pipeline must meet two requirements; first, an appropriate open season should be conducted, and second, enough capacity should be made available for uncommitted volumes. At the same time, deciding whether the common carriage obligation is met requires a consideration of the details of the individual case.

Fair and Equal Opportunity to Access Firm Service

While the *CER Act* does not prescribe specific guidelines governing the open season process, in the past, the National Energy Board ("NEB") has determined an open season process to be appropriate if, as minimum requirements, the process was communicated transparently and consulted on in advance and all parties had fair and equal access to participate in the open season.

The CER determined that aspects of the open season procedures could be appropriate in circumstances where the offered service terms do not create access barriers. However, Enbridge's suggestion raised the concern that aspects of the offering would effectively limit some parties' ability to access firm service through the open season.

The CER found that it was reasonably likely that the open season for Mainline contracting would be oversubscribed if it were to move forward. However, it adopted the view previously held by the NEB that it would not be in the industry's best interest for the CER to dictate the terms and processes for open seasons.

The CER agreed that an open season that provides a fair and equal opportunity for all parties to access capacity, particularly when strongly and broadly supported by stakeholders, can help a pipeline company establish that any discrimination is justified. However, an open season cannot be expected to fully address discrimination faced by future shippers who cannot participate in the open season, nor prospective shippers who face unreasonable barriers to accessing the offering. As such, the CER was not persuaded that the open season would have fully addressed discrimination concerns related to the firm service offering.

Access to Capacity After Implementation of Firm Service

When determining whether an oil pipeline has met its common carriage obligation, the CER considers whether there will be sufficient access to capacity after the implementation of firm service. It found that after implementation of firm service, Enbridge’s proposed reservation of 10 percent of capacity for uncommitted volumes on the Canadian Mainline would not likely provide a meaningful option to access pipeline capacity.

The CER accepted that any reallocation of highly utilized capacity would be expected to result in impacts to parties, both negative and positive. However, the potential levels of apportionment on uncommitted volumes represent an excessive reduction of service quality and access to capacity for uncommitted shippers, when considering other relevant needs, benefits and impacts.

With no new capacity being added as part of the application, the CER found that reallocating capacity from 100 percent uncommitted to 10 percent uncommitted will likely lead to higher levels of apportionment on uncommitted volumes for material periods. Enbridge did not establish that a readily available expansion would reliably address concerns regarding uncommitted capacity, including service quality and access for uncommitted shippers, nor did it provide a compelling justification for the negative impacts on pipeline access.

Need

Enbridge argued that Mainline contracting supports the following needs of Enbridge and the broader market. First, the need to manage Enbridge’s risk exposure. Second, the potential need for additional pipeline capacity from the Wester Canadian Sedimentary Basin (“WCSB”), and third, the need to respond to shippers’ requests. It also submitted that Mainline contracting is necessary for Enbridge to compete on a level playing field with other pipelines.

Enbridge presented the Canadian Mainline’s risk exposure as a key factor in justifying Mainline contracting. In the CER’s view, pipeline risks are a factor to consider when assessing an application for contracting on an oil pipeline, but a specific threshold of material or imminent risk is not necessarily a prerequisite for contracting generally.

The CER found that Enbridge faces some volume risk in the form of both supply risk and competitive risk. It also agreed that Enbridge is entitled to reasonable risk allocation. However, the CER did not find that this risk reasonably justifies the sudden and substantial changes to pipeline access and the other impacts that will potentially result from Mainline contracting.

Enbridge presented Mainline contracting as the only means to facilitate future Canadian Mainline expansions by providing valuable market signals for expansion and by providing assurance that existing capacity will continue to be utilized.

The CER agreed that Mainline contracting could provide some information and risk mitigation. However, it did not agree that it is a prerequisite for Enbridge to pursue future expansion projects.

As part of the need for Mainline Contracting, Enbridge also discussed the request from shippers for capacity and toll certainty and locking in refinery demand for WCSB supply.

The CER determined that there are operational challenges associated with supply unpredictability, and although companies confirmed that they were able to meet their refinery run rates, the CER recognizes that at times they incurred additional costs to do so. The CER considered these challenges to be compelling considerations in this application and weighed them against the absolute flexibility of 100 percent uncommitted capacity preferred by some opposing parties.

Because of the consideration of the benefits against the absolute uncommitted capacity, the CER noted that the benefits of Mainline contracting primarily accrue to a distinct group of market participants. This group has successfully operated its facilities in the absence of firm service. No party suggested that their economic viability would be threatened in the absence of Mainline contracting. However, there was evidence of serious impacts, including on potential viability, for some producers affected by the potential burdens of Mainline contracting.

With respect to securing refinery demand for WCSB supply, the CER agreed that Mainline contracting, and the associated sunk toll obligations, would create an incentive for committed shippers to utilize WCSB production over other supply sources for the length of their contract terms. But the CER was not convinced that this incentive would have a material practical impact on the demand for western Canadian crude oil.

Broader Impacts

The CER noted that efficiency gains are possible and generally in the public interest. While various efficiency gains under the Mainline Contracting Proposal were reasonably likely, the CER found that their significance is uncertain and needs to be measured against other contextual considerations. In this proceeding, the CER generally found that the net benefits were not sufficiently specified or supported by evidence.

Summary of Findings on the Common Carriage Obligation

Firm service under Mainline Contracting, as structured at the time of this decision, does not meet Enbridge's common carriage obligations. Considering the common carriage framework, the CER, in summary, found that there would be an uneven distribution of access to the Canadian Mainline. Generally, enough access to capacity after implementation of firm service needs to be decided on a case-by-case basis. In this case, Enbridge did not provide a basis for the uneven distribution.

After weighing the benefits and adverse effects of Mainline Contracting, the CER determined that the benefits would accrue to Enbridge and a specific set of current shippers. The adverse effects would not be distributed similarly but be carried by a different group of shippers and stakeholders, primarily a group without material refining interest. Further, some benefits are purely speculative or not material.

Considering all available forecasts, the CER sees a considerable likelihood of constrained egress, such that apportionment issues would persist for some time and likely worsen for uncommitted shippers under Mainline Contracting. As a result, Mainline Contracting would not lead to access that complies with the common carriage obligation.

The common carriage and unjust discrimination assessments involve separate statutory obligations. Considerations related to the common carriage obligation overlap with those relevant to unjust discrimination noted in sections 235 and 236 of the *CER Act,* which prohibits unjust discrimination in tolls, services or facilities. The burden to prove that any discrimination is not unfair is placed on the company applying the tolls or providing the service.

The CER determined that the tolls, terms and conditions provided in the application would result in an uneven and disproportionate concentration of benefits without enough justification.

<u>Proposed Tolling Methodology and Terms and Conditions of Service</u>

Enbridge's proposed tolling methodology included committed, uncommitted, receipt and delivery tankage, and receipt and delivery terminalling tolls. The CER had significant concerns regarding the likelihood that the Mainline Contracting tolling methodology would reliably lead to just and reasonable tolls. The CER considered the proposed method of establishing tolls, the international joint tariff methodology, specific attributes of the proposed toll design, including the base toll design and the toll premiums, discounts, surcharges, and adjustments, the potential for abuse of market power and compared the proposed tolls to cost of service tolls and projections of returns on equity ("ROEs") under the proposed methodology.

Enbridge's proposed tolls for committed and uncommitted service are the product of negotiations and not cost-based. As base tolls for proposed services, Enbridge proposed 6.10 $US/bbl for the flex service term committed base toll. As the uncommitted base toll and committed base toll, Enbridge proposed 5.99 $US/bbl and 5.70 $US/bbl, respectively. The base tolls could be subject to surcharges for changes in applicable law, abandonment and decommissioning.

Enbridge proposed a range of contract terms from 8 to 20 years. It noted that opposing parties' proposals for significantly shorter terms ignored the fact that Mainline Contracting is aimed to mitigate Enbridge's long-term risk. Enbridge proposed different types of firm service contracts as options for priority service, including five requirements contract types and three take-or-pay contract types.

The CER found that the risks Enbridge sought to mitigate do not justify the long contract terms. Further, the contract term was too long considering the impacts such long-term contracts would put on shippers and potential barriers to the ability of some to access committed service. Alternative flex service term contracts proposed were not considered acceptable as the open season would likely be oversubscribed.

The combination of the proposed international joint tariff methodology, the uncertainty and disparity involving local tolls and costs associated with the US Lakehead System, and the long-term 20-year fixed toll approach obscured whether the proposed methodology would produce just and reasonable Canadian Mainline tolls. Nonetheless, the CER was persuaded that the available evidence indicates that the proposed tolls could produce unreasonable returns and unreasonably exceed the cost of service tolls on a sustained basis on the Canadian Mainline.

The CER found a lack of compelling reasons to incent long-term commitments to the degree proposed in this application. Favouring committed shippers through the components embedded within the overall toll design and various terms and conditions was not justified and raised concerns about discrimination between the services.

Disposition

The CER denied the implementation of Mainline Contracting and Enbridge's proposed terms, conditions and tolls. The open season will not proceed, and the existing interim tolls and conditions of service remain in effect.

The CER approved the continuation of Enbridge's exemption from the requirement to keep the system of accounts described by the *Oil Pipeline Uniform Accounting Regulations*, but Enbridge must file its financial surveillance reports in full.

The CER also approved adding the Destination Verification ("DSV") Procedure to the Canadian Mainline tariffs. The CER directs Enbridge to file its updated Rules Tariff and the DSV Procedure document with the CER.