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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FEDERAL COURT

Ermineskin Cree Nation v the Minister of Environment and Climate Change, the Attorney General of Canada and Coalspur Mines (Operations Ltd.)
Aboriginal Rights - Duty to Consult

In this decision, the Federal Court decided that the Minister of Environment and Climate Change Canada (the "Minister") had a duty to consult with Ermineskin Cree Nation ("Ermineskin") before designating the Vista Test Underground Mine and Vista Phase II thermal coal projects of Coalspur Mines (Operations) Ltd. under the federal *Impact Assessment Act* ("*IAA*") (the "Designation Order"). The Court found that the Designation Order would adversely impact Aboriginal and Treaty rights ("Aboriginal Rights"), including economic opportunities from the Operations. The designation was quashed.

Background

Ermineskin holds and exercises Aboriginal Rights throughout both the Treaty 6 territory and traditional territory that is approximately 25,000 acres in size ("Traditional Territory"). Ermineskin entered into an Impact Benefit Agreement ("2019 IBA") with Coalspur Mines (Operations) Ltd. ("Coalspur"). Under the 2019 IBA, Coalspur agreed to provide valuable economic, community and social benefits to Ermineskin as compensation for potential impacts resulting from natural resource development on the ability of Ermineskin members to exercise Aboriginal Rights within their Traditional Territory.

Ermineskin's concern was that the Designation Order would adversely impact Aboriginal Rights, including economic opportunities created by its contractual relationship with Coalspur under the 2019 IBA. Ermineskin submitted that the honour of the Crown imposes a duty to consult with Ermineskin on the Minister before making the Designation Order.

The Minister rejected this concern stating that loss of economic, social and community benefits is not an adverse impact related to an Aboriginal or Treaty right. The Minister argued that any connection is indirect, concerns a third party, speculative and contingent compensation for potential adverse impacts to the asserted rights.

2019 and 2020 Designation Processes

In December 2019, the Minister conducted a designation review process and determined that Phase II without the limited Underground Test Mine did not warrant designation under the *IAA*. Ermineskin and 30 other Indigenous groups and federal and provincial agencies were notified and requested to comment. The Minster's decision was consistent with the recommendation of the Impact Assessment Agency (the "Agency") and with concerns raised by Indigenous groups involved.

In July 2020, the Minister issued the Designation Order central to this decision. Ermineskin was not given notice of, nor was it consulted in any way during the process leading to the order designating the Vista Test Underground Mine and Vista Phase II.

The designation process in 2020 was initiated by letters from the Louis Bull Tribe First Nation and the Stoney Nakoda Nation. Several Letters supporting the reversal were submitted. Despite the information from the recent 2019 designation that indicated that Ermineskin was affected by the Designation Order, the Agency and the Minister did not consult Ermineskin or any other potentially impacted Indigenous groups. The consultation was limited to the two Indigenous groups that requested the Designation Order. Against the recommendation from the Agency, the Minister decided to designate the Vista Test Underground Mine and Vista Phase II.

Statutory Scheme for Designation

The *IAA* imposes federal decision-making and the possibility of a requirement for federal impact assessments on "designated projects". Designation under the *IAA* applied to physical activities rather than projects. Physical activities do not come within the scope of the *IAA* unless they, on their own or in conjunction with other physical activities, meet the definition of a designated project set out in the *IAA*.

The *IAA* assesses a wide range of impacts. This includes effects on Indigenous peoples, such as Ermineskin, outlined in the *Operational Guide: Designating a Project under the Impact Assessment Act.* This Operational Guide declares that the Agency will consider, among other things, whether it requires further information from a requester, or federal departments, other jurisdictions, and "potentially affected Indigenous groups" to determine whether the physical activity has the potential to cause adverse effects on "the environment that could affect the Indigenous peoples of Canada" or "the health, social or economic conditions of the Indigenous peoples of Canada," and the potential of the physical activity to cause "adverse impacts on the section 35 rights" of Indigenous peoples.

Analysis of Issues

In its consideration of the Designation Order, the Court applied the correctness standard. It determined, and the Minister agreed, that the Crown has a duty to consult with and, if appropriate, accommodate the interests of Indigenous communities where the conduct contemplated by the Crown may intrude on an Aboriginal right.

In the Court's view, the critical issue, in this case, was whether the duty to consult was triggered by the 2020 designation requests and the process leading to the Designation Order. The Crown was found to have a duty to consult, as it knew its decision can affect a potential Aboriginal claim or right. The Crown had this knowledge because Treaty rights were involved in this case.

However, there was disagreement on whether there was the possibility that the Crown's conduct could affect the Aboriginal claim or right, which would require that the claimant show a causal relationship. Ermineskin argued the Designation Order will "delay, lessen, or eliminate Ermineskin's economic interest" in Phase II and the limited Underground Test Mine. The Minister rejected this submission, arguing that such loss of economic, social and community benefits is not an adverse impact related to an Aboriginal or Treaty right, and does not relate either to Aboriginal title to the land that may be developed, or to the ownership of the coal resource.

In agreeing with Ermineskin, the Court disagreed with the Minister's submission that lost economic benefits do not give rise to any duty to consult. The Court noted that this approach to the duty to consult is too narrow. The Court specified that the duty to consult can be engaged when broader economic interests may be adversely impacted. This was determined to be the case in connection with the 2019 IBA, which creates economic interest related to and derivative from Aboriginal Rights.

Contrary to submission from the Minister, the Court found that potential adverse impacts were not speculative. It found that social, economic and community benefits secured under 2019 IBA were threatened with possible adverse effects by the Designation Order. It also found that losses had already been incurred because the Designation Order was made more than a year prior and had delayed the Phase II and the Test Mine.

Accordingly, the Court determined that the requirements triggering the duty to consult were fulfilled. Therefore, the Crown was required to consult with Ermineskin regarding the Designation Order and its potential adverse impacts on Ermineskin's economic rights.

ALBERTA ENERGY REGULATOR

Invitation for Feedback on New Contamination Management Manual, AER Bulletin 2021-26

Oil and Gas – Regulatory Requirements

The AER is seeking feedback on a proposed new *Manual XXX: Contamination Management*. The purpose of this manual is to assist the industry in understanding the regulatory requirements and expectations for remediating contamination related to conventional oil and gas, in situ, and pipeline activities regulated by the AER.

The manual does not introduce any new requirements; it follows the requirements of the *Remediation Regulation* released under the *Environmental Protection and Enhancement Act* and includes an overview of key concepts and the remedial measures process to support the management and closure of contaminated sites.

Oil Sands Exploration Application Variance Form and Updated Guidance, AER Bulletin 2021-27

Oil and Gas – Regulatory Requirements

On January 8, 2021, Alberta Environment and Parks ("AEP") updated the *Master Schedule of Standards and Conditions* ("*MSSC"*), which introduced new standards, conditions, desired outcomes, and best management practices for oil sands exploration ("OSE") activities the AER administers.

If applicants are unable to meet *MSSC* approval standards, sufficient rationale and mitigation measures should be provided for review with the OSE application. To that end, the AER has developed a new Oil Sands Exploration Application Variance Form for applicants to submit with their application.

Furthermore, the caribou range approval standards and conditions in the *MSSC* now apply to OSE programs and overlap with the caribou protection plans outlined in *Manual 008: Oil Sands and Coal Exploration Application Guide*; as a result, the submission of caribou protection plans outlined in *Manual 008* is no longer required for OSE programs. This change does not lessen caribou protections. The MSSC caribou range standards fully align with and support existing provincial caribou policy.

Applicants should continue to follow *Manual 008* together with the guidance given in this bulletin and the Oil Sands Exploration webpage until a full review of and updates to *Manual 008* can be completed.

***Changes to the Renewal of Public Lands Act Dispositions*, AER Bulletin 2021-28**

Public Lands

Under Bulletin 2021-28, the AER worked closely with Alberta Environment and Parks ("AEP") to create a more efficient process for issuing dispositions under the *Public Lands Act* that allow surface access to public land for energy related activities. The changes are as follows:

- Dispositions originally issued before September 10, 2010 are now designated "legacy".
- For the renewal of legacy dispositions, sketch plans are now acceptable in lieu of survey plans for verification of location and footprint. Survey plans remain always acceptable.
- The existing AEP document *Formal Disposition Renewal* has been updated to incorporate the above.
- AEP has issued a new document, *Legacy Public Lands Disposition Renewal Using Sketch*, as well as a new webpage that outlines eligibility criteria and minimum standards for sketch plans and digital mapping.
- *Manual 018: OneStop Public Lands Application Manual* has been updated to include these changes.

Despite these changes, the AER still has the authority to require a survey plan at any time under section 23 of the *Public Lands Act*.

***Control Well Requirements Rescinded,* AER Bulletin 2021-29**

Gas- Control Wells

Since 2006 data collected from control wells have been used to help the AER understand gas resources found in coal and shale. The AER stated that its understanding of coalbed methane and shale gas had reached a point where it no longer requires this data for resource evaluation or reserves analysis.

As a result, the Government of Alberta has repealed sections 7.025 and 11.145 of the *Oil and Gas Conservation Rules*, which defined control wells and prescribed what data had to be reported. The AER also rescinded *Directive 062: Coalbed Methane (CBM) Control Well Requirements and Related Matters*, which gave additional details and process information. Amendments to related instruments are in progress.

These changes mean that control wells will no longer be designated, and the particular data these wells reported will no longer be submitted. All other reporting requirements remain unchanged. There is, therefore, no effect on public safety, environmental protection, or resource conservation.

***New Release Reporting Form,* AER Bulletin 2021-30**

Facilities - Applications

The AER published a new edition of its release reporting form. The new format makes it easier for the licensee to focus on the questions relevant to the release. The AER also streamlined the questions, bringing them up to date with current requirements and reducing duplication. This form will allow the AER to consistently determine the level of review around contamination management while protecting public safety and the environment.

ALBERTA UTILITIES COMMISSION

Improvements to Municipal Franchise Agreement Applications, AUC Bulletin 2021-13
Municipal Franchise Fee Applications

The AUC introduced improvements to the application and approval process for municipal franchise agreements. The changes will reduce the regulatory burden and improve efficiency and limit the review time of these applications to five days.

Extension of the Trusted Traveler Approach

The AUC is extending the checklist, trusted traveler approach introduced in AUC Bulleting 2020-15 to template-based municipal franchise agreement applications. AUC Rule 029: *Applications for Municipal Franchise Agreements and Associated Franchise Fee Rate Riders* sets out a streamlined process for applications requesting approval of electric or gas municipal franchise agreements based on AUC-approved templates. To further improve the application process set out in Rule 029, the AUC will align the trusted traveler approach in cases where:

- there are no changes between the applied-for municipal franchise agreement and the applicable, approved template;

- there are no objections to the applied-for municipal franchise agreement; and

- the municipal franchise agreement complies with all legislative and regulatory requirements, such as the term of the agreement and the maximum franchise fee.

Automation of the Application Process for Municipal Franchise Agreement Applications

The AUC is also introducing an automated application process for all municipal franchise agreements through the AUC's eFiling System. This process requires the same information typically provided in previous applications for municipal franchise agreements but removes the need for the applicant to file a stand-alone application that must be uploaded.

The AUC expects this automated process to reduce the time required to prepare and submit the applications. The process will also increase the consistency of information being provided with the applications and reduce the time needed for the AUC to process the applications.

***Rate Rider Phase of the Utility Payment Deferral Program,* AUC Bulletin 2021-14**
Rates - COVID-19

The Utility Payment Deferral Program ("UPDP") was announced by the Government of Alberta in March of 2020 to alleviate some of the financial hardship directly related to the COVID-19 pandemic. It provided Albertans with the opportunity to defer electricity and gas bills until June 18, 2020, without penalty.

The second phase of the program closed on June 18, 2021. In that phase, customers who deferred payments had until June 18, 2021, to repay their deferred amounts. This third phase runs until June 18, 2022. In this phase, any utility bill payment amounts that were deferred and not repaid will be collected through an electricity rate rider and a natural gas rate rider from all Alberta customers.

Sections 11 and 21 of the *Utility Payment Deferral Program Act* require the AUC to initiate a proceeding as soon as practical on or after June 19, 2021, to establish:

- An electricity rate rider to recover the funding that has not been repaid to the Balancing Pool and the Alberta Electric System Operator by electricity service providers and to recover unpaid deferral amounts owing to self-funded electricity service providers.

- A gas rate rider to recover the funding that has not been repaid to the Government of Alberta and the deferred gas transmission charges owed to the gas distributors and to recover unpaid deferral amounts owing to self-funded gas service providers.

The AUC has established the following process directions to expedite the rate rider proceedings:

- Applications from all eligible applicants were due on Friday, July 16, 2021.

- Eligible applicants are to submit their applications separately through eFiling using either the gas or electric application type: Utility payment deferral rate rider.

- Active participation in the proceeding will be restricted to eligible applicants.

- Any other person interested in this proceeding will be able to register in the proceeding as an observer but will not have active participant status.

Following the receipt of all applications, the AUC will consolidate them into a separate gas and electricity proceeding for issuing two rate rider decisions, one for each of the electricity and gas rate riders.

***Changes to the AUC Participant Involvement Program and Related Information Requirements,* AUC Bulletin 2021-15**

Process - COVID-19

In response to restrictions and public health measures having been lifted in Alberta, the AUC introduced changes to its participant involvement program ("PIP"). These changes reduce the notification period and remove restrictions on permissible meetings and consultations for applicants while encouraging practical flexibility and stakeholder preferences. The AUC expects these changes to support regulatory efficiency.

In 2020, to mitigate the risk of COVID-19 to its stakeholders, its employees, and its work critical to Alberta's essential utility services, the AUC implemented changes and requirements regarding its PIP in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and Rule 020: *Rules Respecting Gas Utility Pipelines.*

As COVID-19 related health measures have been lifted, the AUC made further changes to its PIP requirements. These new requirements are the following:

- Given the possibility that different communities may be subject to varying levels of local COVID-19 response or restrictions, applicants must give stakeholders a minimum of 14 calendar days to receive, consider, and respond to project notifications. The AUC recognizes that all communities are not in the same state of readiness to reopen, and applicants should give extra time where warranted. The Commission will then assess the adequacy of PIPs on a case-by-case basis.

- Open houses and town hall meetings are no longer disallowed, and the AUC no longer discourages face-to-face consultation but recognizes the continued practicality of alternative communication. Applicants have the discretion to consider whether such forms of communication are appropriate in the circumstances, taking into account expressed preferences of stakeholders for a certain form of communication where possible.

- Applicants must provide electronic lists of stakeholder contact information in the format required in Bulletin 2020-13.

The AUC repeated its encouragement and expectation of applicants to be sensitive to the potential ongoing capacity challenges of Indigenous groups and to build additional time into their PIPs.

***Alberta Electric System Operator Bulk and Regional Rate Design Application – Participant Costs,* AUC Bulletin 2021-16**
Rate Design

The Alberta Electric System Operator ("AESO") will, until October 15, 2021, consult on proposed changes to the design of the bulk and regional rates under its Rate Demand Transmission Service ("Rate DTS") and the tariff treatment of energy storage.

Bulk and regional charges account for a significant portion of transmission wires costs. The existing rate design has been largely in place since 2006. The AUC is aware of the significant amount of stakeholder interest in this upcoming application and that revisions to the bulk and regional rate design may have significant impacts on different customers or customer groups.

As a result of the significant stakeholder interest, and in an effort to promote the efficient processing of the AESO's application, the AUC will consider applications for cost eligibility from customer groups who are proposing to actively participate in this AESO bulk and regional tariff proceeding, including customer groups who are not ordinarily eligible to claim costs under Rule 022: *Rules on Costs in Utility Rate Proceedings*. The AUC may also consider, in some circumstances, relaxing the application of the scale of costs for an expert if a customer group who is granted eligibility to claim costs demonstrates that the scale of costs will be inadequate to retain the necessary expertise to address the application and contribute in a meaningful way to the AUC's understanding of the issues.

The AUC invited any customer group that intends to actively participate in this upcoming proceeding and claim costs for any part of the costs of its participation in the proceeding to submit an application for costs eligibility by August 11, 2021.

The AUC expects to order the AESO to pay the costs awarded for eligible interveners that do not have their own hearing cost reserve account or other mechanisms to recover AUC-approved hearing costs.

The AUC created Proceeding 26711 for the purpose of addressing intervener costs. Parties were to file their costs submissions on the record of this proceeding. The AUC requested parties to propose some form of partial cost recovery where they have the means to fund a portion of their participation themselves.

The AUC noted that it would also consider an advance of costs up to 50 percent of a participant's budget. Prospective parties are reminded that a determination of costs eligibility or an advance of costs is not a full indemnity for incurred costs. The AUC will make its final assessment of costs to be awarded at the conclusion of the AESO bulk and regional rate design application proceeding upon its review of the claimants' costs claims prepared in accordance with Section 9 of Rule 022.

***Applications for Lanfine North Wind Power Project Connection,* AUC Decision 26176-D01-2021**
Facilities – Wind Power

In this decision, the AUC approved applications from the Alberta Electric System Operator ("AESO") and facility applications from ATCO Electric Ltd. ("AE") and AltaLink Management Ltd. ("AML") for the proposed Lanfine North Wind Power Project Connection (the "Project Connection"). The AUC found that AE's preferred West route is in the public interest.

<u>AESO Need Identification Document Application</u>

The AESO filed a need identification document ("NID") application as required pursuant to Section 34 of the *Electric Utilities Act* ("*EUA*"). The NID application was filed in response to the system access service ("SAS") request filed by Pattern Development Lanfine Wind ULC ("Pattern"). In the SAS request, Pattern requested access to the Alberta Interconnected Electrical System ("AIES") for its Lanfine North Wind Power Project (the "Wind Project").

The AESO's application proposed the construction of a 13-kilometer transmission line to connect an existing substation to Pattern's approved Buffalo Bird 601S Substation. The NID application also proposed to alter the existing substation and to add or modify other equipment needed to ensure proper integration of the Wind Project with the AIES.

The AUC determined that the AESO's application provided all the information required by the *EUA*, the *Transmission Regulation* and Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. As no interested party argued that the assessment of the need is technically deficient or approval of the needs application is not in the public interest, the AUC considered the AESO assessment to be correct and approved the NID application.

AE Facility Applications

AE applied for approval to construct and connect a 144-kilovolt ("kV") transmission line from the existing substation to Pattern's Buffalo Bird 601S Substation and to add one 144-kV circuit breaker at the existing substation. AE proposed a West route and an East route for the 13 km transmission line, which would be designated as Transmission Line 7L238.

The AUC noted that the West route, preferred by AE, was further away from any residences along the route. The West route also had the lowest overall impact on agricultural operations and would achieve better compatibility with existing land use. Beyond these differences, the AUC noted that the routes were similar.

An environmental evaluation conducted by Hemmera Envirochem Inc. ("Hemmera") concluded that overall, the East route is preferred from the perspective of minimizing potential environmental effects while predicting that residual environmental effects would be similar.

Relying on Hemmera's assessment of the potential environmental effects, the AUC determined that with the imposition of conditions and mitigation measures, the environmental effects of AE's proposed facilities and the West route in particular, could be minimized to an acceptable level. To ensure this, the AUC issued a number of conditions to minimize environmental impacts during the construction and operation of the facilities.

AML Facility Applications

AML requested approval to construct and operate a four-km underground fiber optic cable to support the connection of the Wind Project to the AIES and to construct equipment to prevent overload conditions on the AIES as a result of the Wind Project. The route of the cable would be from an existing splice box on Structure 391 of AE's Eastern Alberta Transmission Line to AML's existing North Holden 395S Substation located approximately 250 km from the Wind Project. The need for the equipment was outlined in the NID and the AESO's functional specifications. The AUC found AML's applied-for facilities are consistent with the need identified in the AESO's NID application, and in the public interest for the reasons described in Decision 26439-D01-2021.

AUC Decision

The AUC approved the AESO's NID application pursuant to Section 34 of the *Electric Utilities Act*. Pursuant to sections 14, 15, 18, 19, and 21 of the *HEEA*, the AUC approved AML's and AE's applications.

The AUC noted that it does not typically issue a permit and license for fiber optic cable applications. However, Decision 26439-D01-2021 issued a permit and license, and connection order which will remain in effect for the Lanfine North Wind Power Project Connection even if the Garden Plain Wind Power Plant Connection Project should be delayed or canceled. Accordingly, the AUC determined that it was appropriate to issue both a permit and license for AML's applied-for facilities and a connection order.

***BA4 Wind GP Corp. Buffalo Atlee Wind Farm 4,* AUC Decision 26434-D01-2021**

Wind Farm - Electricity

In this decision, the AUC approved the application from BA4 Wind GP Corp. ("BA4") to construct and operate the Buffalo Atlee Wind Farm 4 wind power plant and to connect the power plant to FortisAlberta Inc.'s 25-kilovolt distribution system (the "Project").

Application

The Project consists of two wind turbines operated at 5.0 MW, with a hub height of 102.5 meters and a rotor diameter of 145 meters. The Project includes access roads, an underground collector system, a control building and control equipment and is located primarily on private lands. BA4 filed a letter from FortisAlberta Inc. indicating that FortisAlberta Inc. is prepared to connect the power plant to its 25-kilovolt electrical distribution system pending the final execution of an interconnection agreement.

Discussion and Findings

The AUC found that the application included all information required by sections 11 and 18 of the *Hydro and Electric Energy Act* ("*HEEA*")*,* Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and Rule 012: *Noise Control.*

Considering issues found in the renewable energy referral report issued by Alberta Environment and Parks Fish and Wildlife Stewardship ("AEP") regarding adverse impacts to wildlife, the AUC imposed conditions to minimize the Project's effects on tame grassland. As a condition of approval, the AUC required that BA4 does not perform any constructions activities between April 1 and July 15, as described in the *Wildlife Directive for Alberta Wind Energy Projects.* Further, if construction activities are to occur in this area between July 16 and August 24, an experienced wildlife biologist shall conduct nest sweep surveys and implement mitigation measures as outlined in the environmental evaluation for the Project if active breeding bird nests are detected.

To comply with Rule 033: *Post-Approval Monitoring Requirements for Wind and Solar Power Plants,* BA4 is required to submit a post-construction monitoring survey report to AEP and the AUC. This report is to be submitted within 13 months of the Project becoming operational and, as required by AEP pursuant to Rule 033, on or before the same date every following year.

The AUC determined that through compliance with these conditions and through the implementation of the mitigation measures suggested by AECOM Canada Ltd. in its environmental evaluation report, filed as part of BA4's application, residual environmental effects of the Project will be limited.

AUC Decision

The AUC approved that application to construct and operate the Buffalo Atlee Wind Farm 4 pursuant to Section 11 of the *HEEA.* Pursuant to Section 18 of the *HEEA*, the AUC granted the order to connect the wind farm to FortisAlberta Inc.'s distribution system.

***Battle River Power Coop Code of Conduct Compliance Plan Amendments,* AUC Decision 26462-D01-2021**

Code of Conduct Compliance Plan

In this decision, the AUC approved the application from Battle River Power Coop ("Battle River") to amend its *Electric Utilities Act* Code of Conduct Regulation Compliance Plan ("Compliance Plan") subject to a change ordered by the AUC.

Pursuant to Subsection 32(2) of the *Code of Conduct Regulation* ("*CCR*"), Battle River requested approval of changes to its Compliance Plan to reflect changes introduced to the *CCR* on November 12, 2020.

The AUC found that the Compliance Plan contained no provision for the creation and retention of the records required for the AUC to carry out its future audits, as required under Section 40 of the *CCR*. Accordingly, the AUC required that Battle River includes the following text in its Compliance Plan after the policy statement in Section 40.0 “Audit”:

- Battle River Power Coop will retain all code of conduct compliance records listed under Appendix A to its Electric Utilities Act Code of Conduct Regulation Compliance Plan for at least three years. The Commission may amend Appendix A from time to time on notice, and absent a registered objection, the proposed changes to the appendix will take effect within ten business days from the date of the notice.

BluEarth Renewables Inc. Wheatcrest Solar Project, **AUC Decision 26496-D01-2021**
Facilities – Solar Power

In this decision, the AUC approved the application from BluEarth Renewables Inc. (“BluEarth”) to construct and operate the Wheatcrest Solar Project, a 60-megawatt solar power plant (the “Power Plant”).

Application

The Power Plant would consist of approximately 136,000 575-watt photovoltaic solar panels and associated racking systems, including 21 electrical inverters and 21 pad mount transformers. The Power Plant will be located on privately owned land southeast of Lomond.

A new substation and transmission line will also be constructed to connect the Power Plant to the AltaLink Management Ltd. transmission system. BluEarth would submit applications for these facilities in the future.

BluEarth submitted the information required pursuant to the *Hydro and Electric Energy Act* (“*HEEA*”) and Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments.* This included a renewable energy referral report issued by Alberta Environment and Parks Fish and Wildlife Stewardship (“AEP”) that concluded that the Power Plant would result in a low risk to wildlife and wildlife habitat. It further included an environmental impact assessment that indicated that any potential adverse effects of the Power Plant could be effectively mitigated.

In response to information requests, BluEarth submitted that it would engage an independent third-party assessment of decommissioning and reclamation costs and would create a reserve account to cover these costs at the end of the project’s useful life of 35 years. Further, BluEarth submitted that it did not consult with Indigenous groups because the Power Plant is proposed on previously disturbed private cultivated land, does not limit right-of-access for Indigenous communities, and is greater than two km from the nearest reserve.

AUC Findings

The AUC reviewed the application and determined that the information requirements specified in Rule 007 have been met. As BluEarth submitted that it had not yet finalized the design or equipment of the Power Plant, the AUC, as a condition for approval, required BluEarth to file a letter to the AUC that identifies the make, model, and quantity of the equipment and the final equipment layout. This letter must also confirm that the finalized design of the Power Plant will not increase the land, noise and environmental impacts from what was approved for the base reference case by the AUC and it must be filed no later than one month before beginning construction.

The AUC accepted the prediction set out in the solar glare assessment submitted that the evaluated receptors would experience zero glare from the Power Plant based on its specific design. However, to account for the circumstances of the submitted assessment, the AUC required that BluEarth:

- uses anti-reflective coating on the solar panels; and

- provides an update to the AUC specifying the final backtracking design of the solar panels and confirms that the final backtracking design is consistent with the design approved by the AUC and will not result in glare for any of the receptors considered in the solar glare assessment. The update is to be filed no later than one month before construction is scheduled to begin. This update may be part of the letter confirming the final Power Plant design.

To ensure that issues associated with solar glare are addressed in a timely manner, BluEarth was further required to file a report detailing any complaints or concerns it receives or is made aware of regarding solar glare from the Power Plant during its first year of operation, as well as the response to the complaints and concerns. Finally, the AUC required that BluEarth submits to AEP and the AUC annual post-construction monitoring survey reports pursuant to Subsection 3(3) of Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants.*

AUC Decision

The AUC determined that approval of the Power Plant is in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act* having regard to the social, economic, and other effects of the Power Plant, including its effect on the environment. Pursuant to Section 11 of the *HEEA*, BluEarth's application was approved.

***Cambridge Park Home Owners Association Review and Variance of Decision 26429-D01-2021,* AUC Disposition 26640-D01-2021**

R&V - Rates

The AUC dismissed the application from the Cambridge Park Home Owners Association ("Home Owners") for a review and variance ("R&V") of Decision 26429-D01-2021 (the "Review Application").

Background

In Decision 26429-D01-2021 (the "Original Review Decision"), a review panel approved an application from AMAR Developments Ltd. ("AMAR") to review and vary the method used in Decision 25519-D02-2021 (the "Final Rates Decision") to calculate the variable charge. In the Original Review Decision, the review panel found that AMAR demonstrated that an error existed, on a balance of probabilities, with respect to the accounting methodology used to calculate monthly costs based on a monthly average over the entire period of 2020, which was mismatched with the approved revenue requirement for the period from May to December 2020.

In its Review Application, the Home Owners asserted that the review panel erred in the calculation of final rates for 2021 by failing to acknowledge overcollections by AMAR in the period from January to April 2020.

Does the Ground Raised by the Home Owners Relate to a Determination Made in Decision 26429-D01-2021?

The Home Owners argued that calculation errors had been made as AMAR was already overcharging customers from January to April 2020 to cover the additional usage requirements in the upcoming summer and fall months. Further, the Home Owners submitted that revenues collected for the entire year 2020 should have been considered to fairly calculate the refund or deficit.

The AUC determined that the finding that the Home Owners sought to have reviewed was made by the AUC in Decision 25519-D02-2021. No new finding was made regarding the revenues collected by AMAR from January to April 2020 in Decision 26429-D01-2021. The current review panel determined that the issue was known to the Home Owners prior to the issuance of Decision 26429-D01-2021. Therefore, the Home Owners were in a position to file their own review application following the issuance of the final rates decision.

The Review Application was filed 138 days following the issuance of the final rates decision that the Home Owners seek to have reviewed. However, the AUC found that the Home Owners could have filed the Review Application within the 60-day time period following the issuance of the final rates decision.

Finality and Certainty of AUC Decisions

AUC decisions are intended to be final and a review should only be granted in those limited circumstances described in Rule 016: *Review of Commission Decisions*. Only in exceptional circumstances should review decisions ever be subject to further review.

The current review panel was not persuaded that exceptional circumstances, such as the existence of an overriding and palpable error, apply that would weigh in favour of setting aside the principles of finality and certainty to allow the late Review Application. Further, and in the alternative, the current review panel finds that exceptional circumstances are not engaged in the Home Owner's review application of the Original Review Decision, and the Home Owners did not demonstrate the existence of an error that is material to the Original Review Decision. Accordingly, the AUC determined that the Home Owners did not fulfill the requirements for a further review set out in Rule 016.

Cypress Renewable Energy Centre GP Inc. and Cypress 2 Renewable Energy Centre GP Inc. Cypress Wind Power Project Amendments, **AUC Decision 26489-D01-2021**
Facilities – Wind Power

In this decision, the AUC approved the application from Cypress Renewables Energy Centre GP Inc. ("Cypress GP") and Cypress 2 Renewable Energy Centre GP Inc. ("Cypress 2 GP", collectively, "Cypress"), to alter the Cypress Wind Project.

Application

Cypress applied for permission to expand the Cypress Wind Power Plant (the "Power Plant"), located in the Medicine Hat area, from 201.6 megawatts ("MW") to 248.4 MW in two phases. It further requested approval to change the turbine specifications and locations.

Cypress submitted that the applied-for change to the turbines is to bring the Power Plant up to date with advancements in wind turbine technology. The changes would result in minor changes to the design of the Power Plant but increase the generating capacity.

Cypress applied to split the Power Plant into two phases to be developed concurrently and for an ownership change. Phase 1 would continue to be owned by Cypress GP on behalf of Cypress Renewable Energy Centre Limited Partnership and would consist of 39 turbines. Phase 2 would be owned by Cypress 2 GP on behalf of Cypress 2 Renewable Energy Centre Limited Partnership and would consist of nine turbines.

AUC Findings

The Cypress Wind Power Project had been approved but not yet constructed. Accordingly, the AUC considered any incremental impacts that may result from amendments and time extensions. As the changes included changes to the hub height and rotor length of the turbines, the AUC evaluated changes in the shadow flicker impacts. A revised shadow flicker assessment demonstrated that dwellings would not experience more than 18.4 hours of shadow flicker per year. The assessment concluded that 19 dwellings might experience the same or decreased annual shadow flicker impacts, and 14 dwellings may experience minor increases in annual shadow flicker impacts. Cypress contacted each affected stakeholder to discuss the revised assessment and confirmed that there are no objections or concerns arising from the revised assessment.

The AUC found that there were no outstanding public or industry objections or concerns related to the proposed changes. It found the changes to be in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act*, the AUC approved the applications pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act.*

***Determination of the Compensation Amount to be Paid by EPCOR Distribution and Transmission Inc. to Battle River Cooperative REA Ltd.*, AUC Decision 26318-D01-2021**

Service Area - Compensation

In this decision, the AUC determined that it is reasonable that EPCOR Distribution and Transmission Inc. ("EPCOR") pays $783,940 in compensation to Battle River Cooperative REA Ltd. ("Battle River") in relation to the transfer of electric distribution system assets to EPCOR as directed by the AUC in Decision 25300-D01-2020. The AUC also found it reasonable to compensate Battle River in the amount of $67,179 for the construction of distribution system facilities that were required to maintain electric services to Battle River members located outside of the annexed area that was affected by the annexation and transfer of assets ordered by the AUC.

Background and Procedural Summary

In 2019 EPCOR was provided with the exclusive rights to provide electric distribution service to lands annexed as a result of the City of Edmonton expanding its municipal boundaries. Parts of this area were within the service area of Battle River. In Decision 25300-D01-2020, in response to the annexation of the land, the AUC ordered changes to service area boundaries and the transfer of Battle River distribution system facilities and its members within the annexed areas to EPCOR.

EPCOR and Battle River were not able to reach an agreement regarding compensation. As a result, EPCOR requested a decision from the AUC to determine the compensation to be paid to Battle River and proposed a purchase price of $0.784 million based on replacement cost new less depreciation ("RCN-D") valuation methodology.

The AUC's Discretion to Determine a Compensation Methodology

The AUC had to determine if it is limited in determining compensation based on types identified under Section 29(4)(c) of the *Hydro and Electric Energy Act* ("*HEEA*"), or if it has the discretion in determining compensation under Section 32(2)(b) of the *HEEA.*

EPCOR argued that, because there was no agreement between it, as the acquiring public distribution facility owner, and the transferring Rural Electrification Association ("REA") regarding compensation, Section 29(4)(c)(i) of the *HEEA* mandates the use of reproduction cost new less depreciation in respect of compensation for transferred assets. EPCOR's application valued compensation based on replacement cost new less depreciation, not reproduction cost new less depreciation.

Battle River argued that Section 32(2) indicates legislative intent for the AUC to consider compensation issues in the context of the particular facts and matters of that issue. It further argued that interpretation of the *HEEA* must include the context of REAs under the *Rural Utilities Act* and the legislature's intent to provide a unique place for REAs in Alberta.

The AUC determined that Section 32 of the *HEEA* is more specific than Section 29, as Section 32 only applies if: (i) an REA is subject to a Section 29 order; and (ii) the AUC by order transfers to another person the service area or part of it served by the REA. Accordingly, Section 29 must give way to Section 32 of the *HEEA*.

The AUC found that it has the authority to determine if and what amount of compensation is payable to Battle River under Section 32(2)(b) of the *HEEA* in the circumstances and is not bound by a particular methodology regarding valuing the facilities that were ordered transferred.

Compensation Methodology to be Used to Determine the Purchase Price

EPCOR proposed a compensation amount of $0.784 million by applying the RCN-D valuation methodology to the transferred assets.

An independent witness for Battle River argued that a fair market value ("FMV") calculation resulting in a payment of $1.544 million, representing the foregone revenues related to the transferred assets, would be acceptable. Alternatively, the Battle River witness suggested revising the engineering and contingency rates in EPCOR's RCN-D calculation schedules and then separately adding compensation amounts referenced under Section 29(4) of the *HEEA*. This alternative method resulted in a compensation amount of $2.157 million.

The AUC determined that the RCN-D compensation method proposed by EPCOR should apply. The AUC repeated its acknowledgment that RCN-D is not the only method that can be used to determine a purchase price for acquired assets. The AUC found that EPCOR's approach, which included a comprehensive on-site assessment of Battle River's assets to be transferred, and the application of EPCOR's estimating method that has been previously approved by the AUC, to be reasonable for calculating the purchase price of Battle River's electric distribution system related to the transferred assets in the circumstances. Further, the RCN-D calculation has been used repeatedly in previous cases in the valuation of assets acquired by distribution utilities from REAs and municipalities.

The AUC found that the FMV calculation conducted on behalf of Battle River was similar to a discounted cash flow calculation. It determined that the calculation was overly simplistic and based on figures that do not reflect the economic reality of the assets that are to be acquired.

Calculation of RCN-D

EPCOR calculated an RCN amount of $1.757 million based on asset information, operations and maintenance practices, and inspections and surveys of the facilities. To calculate the cost of replacing the transferred facilities, EPCOR used its bottom-up budgeting approach and estimated the material, labour, equipment, subcontractor and engineering costs premised on its current design, engineering and construction standards. EPCOR used an engineering rate of 8.8 percent and a contingency rate of zero percent to estimate the cost of replacing the transferred facilities. EPCOR noted that the engineering rate is based on historic actual engineering costs for similar types of work activities and supported the contingency rate by confirming that contingency is built into its costs estimates. The AUC found this approach and the engineering and contingency rates to be reasonable.

EPCOR applied its AUC-approved Direct Life Method ("DLM") to determine the depreciation rates, and accumulated depreciation amounts to calculate the D component of the RCN-D formula in the amount of $0.973 million, which was approved by the AUC.

The AUC found no reasonable basis to apply any adjustments to EPCOR's proposed RCN-D amount of $783,940.

Compensation for Facilities Alterations Outside of the Annexed Area

Battle River requested that the AUC approve an additional payment from EPCOR of $69,389.25 to compensate it for the construction of distribution system facilities that were required to maintain electric services to Battle River members located outside of the annexed area.

EPCOR accepted the costs claimed by Battle River, except for $2,210.51 that Battle River had incurred in relation to a Battle River member that no longer required electric service. Battle River explained that the service in question required a distribution system alteration to ensure electric services were maintained after the transfer of assets. Because the service was idle, Battle River decided to salvage the facilities rather than making alterations because this was the most cost-effective solution. The AUC found that the timing of the discovery of the idle service should have no bearing on the decision to salvage the service.

Accordingly, the AUC approved an additional payment from EPCOR to Battle River of $67,179.

Order

The AUC ordered EPCOR to pay $783,940 in compensation in respect of the transfer of the electric distribution system assets ordered in Decision 25300-D01-2020 to Battle River. EPCOR was ordered to pay a compensation amount of $67,179 in respect of the electric distribution system facilities constructed by Battle River that were required to maintain electric services to Battle River members located outside of the annexed area that were affected by the annexation and transfer of assets ordered in Decision 25300-D01-2020.

Enterprise Solar GP Ltd. Enterprise Solar Project, AUC Decision 26322-D01-2021

Facilities – Solar Power

In this decision, the AUC approved applications from Enterprise Solar GP Inc. ("Enterprise Solar") for permission to construct and operate the Enterprise Solar Project (the "Project").

Applications

The Project consists of a 65-megawatt solar power plant and an associated substation. The Project and the substation will be located on privately owned land near the town of Vulcan. The Project consists of approximately 157,000 bi-facial photovoltaic modules and other materials and infrastructure.

The connection of the Project to the Alberta Interconnected Electric System would be the subject of a separate application. The Project is expected to come into service in the fourth quarter of 2022, with construction beginning in the third quarter of 2021.

AUC Findings

The AUC was satisfied that the application and associated information filed by Enterprise Solar fulfilled the requirements applicable to solar power plant applications.

As predictions submitted by Enterprise Solar as part of its solar glare assessment were based on the use of anti-reflective coatings, the AUC required that anti-reflective coating be used on the Project solar panels. The AUC required Enterprise Solar to file a report detailing any associated complaints or concerns it receives or is made aware of during its first year of operation, as well as Enterprise Solar's responses.

As required by Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants* Enterprise Solar, is further required to submit an annual post-construction monitoring survey report to AEP and the AUC. This report is to be filed within 13 months of the Project becoming operational.

The AUC noted that approval of the energy storage system, with bi-directional inverters and space for potential future battery equipment would require a separate application.

The AUC considered the Project to be in the public interest, as required by Section 17 of the *Alberta Utilities Commission Act*. Pursuant to Section 11 of the *Hydro and Electric Energy Act*, Enterprise Solar's application for construction and operation of the Enterprise Solar Project was approved. The application to construct and operate the associated substation was approved pursuant to sections 14, 15 and 19 of the *Hydro and Electric Energy Act*.

EPCOR Distribution & Transmission Inc. 2021 Customer Specific Distribution Access Service Rate Update for an Existing Customer (CS40), AUC Decision 26619-D01-2021

Electricity - Rates

In this decision, the AUC approved the update made by EPCOR Distribution & Transmission Inc. ("EPCOR") to its customer specific ("CS") distribution access service ("DAS") rate for an existing customer ("CS40") of $163.82 per day, effective September 1, 2021.

Background

The CS rate class includes customers with energy demands over 5000 kilowatts. In October 2020, the CS40 customer requested a buy-down of its contracted minimum demand of 6.56 megavolt ampere ("MVA") to a revised contracted minimum demand of 5.0 MVA. EPCOR executed the requested change according to its distribution connection services terms and conditions.

Calculation of the 2021 CS40 Rate

EPCOR noted that cost-of-service calculation of CS rates generally includes three components: incremental equipment and installation activities; cost of existing assets to provide service; and allocated operating, maintenance and general ("OM&G") costs. To determine the capital cost component of the assets in service in the customer's rates, EPCOR used the previously approved direct calculation method.

Regarding equipment and installation activities, EPCOR confirmed that assets used to provide the standby service are included in the rate for the site, and no incremental assets were required to provide service to the customer. Regarding OM&G costs, EPCOR submitted that it allocated OM&G costs associated with the incremental and existing assets using a ratio of 1.851 per dollar of capital costs. EPCOR calculated the ratio between total OM&G costs and capital costs based on the amounts from its last Phase II application.

The AUC reviewed EPCOR's submissions and calculations and approved the proposed CS40 rate update. The CS40 rate of $163.82 per day will come into effect on September 1, 2021. The AUC emphasized that, in approving the requested rate update, it did not authorize the recovery of any amount payable by the customer from other EPCOR customers in the event of default or bankruptcy of CS40.

EPCOR is also required to true up any differences if the actual effective date for the revised CS40 rate differs from the approved date of September 1, 2021. The CS40 rate will further be trued up to reflect the 2021 actual cost of debt when it becomes available.

***EPCOR Distribution and Transmission Inc. Correction of 2020 and 2021 Maximum Investment Levels,* AUC Decision 26648-D01-2021**

Rates - Maximum Investment Levels

In this decision, the AUC partially approved the request made by EPCOR Distribution & Transmission Inc. ("EPCOR") to correct its 2020 and 2021 maximum investment levels ("MILs").

EPCOR's corrected MILs for qualifying projects beginning July 30, 2021, and onward were approved. For qualifying projects undertaken before that date, the AUC noted that EPCOR may choose to refund amounts accrued due to its error in the calculation of its 2020 and 2021 MILs. However, the AUC did not approve the tariff changes that would result from addressing the error for 2020 and 2021 as applied for by EPCOR.

Background

EPCOR applied to the AUC to correct its MILs. EPCOR explained that an error initially discovered and addressed in its 2019 annual performance-based regulation ("PBR") rate adjustment filing was inadvertently carried forward into the 2020 and 2021 annual PBR filings. This error, remedied by EPCOR in this filing, resulted in corrected 2020 and 2021 MIL amounts.

Analysis

Retroactively Changing MILs

EPCOR's MIL amounts for 2020 and 2021 had previously been finalized by the AUC. Accordingly, the AUC found that ordering a refund and allowing EPCOR to earn a return on the marginal investment for the period of January 1, 2020, to July 29, 2021, would constitute impermissible retroactive ratemaking.

EPCOR's application would result in a refund of money to developers and others. In return, EPCOR would have an opportunity to invest incrementally in its distribution system. However, the AUC considered that allowing EPCOR to true up and earn a return on a past error is counter to sound ratemaking practices. Approval of this application as filed could result in an incentive for other distribution utilities to search through finalized rates in an attempt to benefit from an error to change rates or earn a higher return on its capital investment.

Conclusion

Because of its concerns with retroactive ratemaking, the AUC approved EPCOR's corrected MILs for qualifying projects beginning July 30, 2021. For projects undertaken from January 1, 2020, to July 29, 2021, where EPCOR invested in accordance with the MILs approved in Decision 24882-D01-2019 or Decision 25866-D01-2020, the AUC could not approve the tariff changes that would result in EPCOR adjusting its MILs retroactively.

The AUC acknowledged EPCOR's submission that expensing the marginal investment would harm EPCOR and lead to additional expenses in 2021 that were not considered in the establishment of its PBR rates. Therefore, as EPCOR has been making investments in accordance with its finalized terms and conditions of service in 2020 and 2021, it is under no obligation to provide refunds and expense the resulting marginal investment from projects undergone on or prior to July 29, 2021.

***FortisAlberta Inc. 2022 Phase II Distribution Tariff Application,* AUC Decision 25916-D01-2021**

Rates - Distribution

In this decision, the AUC addressed the 2022 Phase II distribution tariff application filed by FortisAlberta Inc. ("FortisAB"). Subject to certain modifications, the AUC approved FortisAB's proposals regarding transmission and distribution cost allocation and rate design. The AUC did not approve FortisAB's proposals regarding the reallocation of shared system costs among small capacity rate classes; revenue-to-cost ratios and resulting bill impacts; and terms and conditions.

With respect to the distribution costs related to Rural Electrification Associations ("REA"s), the AUC found that the costs attributable to serving REAs should be addressed under an integrated operating agreement ("IOA"). With the exception of load settlement costs attributable to and recovered from REAs, REA farm transmission credits, and the REA distribution system use credit, REA-related costs must be removed from the rates charged to FortisAB's distribution customers at the time of its 2023 cost-of-service application. In addition, FortisAB was directed to return any costs attributable to REAs that it recovers under the IOAs dollar-for-dollar by a Y factor during the remainder of the current performance-based regulation ("PBR") period.

Transmission Cost Allocation

FortisAB is required to pay, on behalf of its customers, for transmission service provided by the AESO. FortisAB treats its transmission access costs separately from its distribution costs. FortisAB allocates these transmission charges to its customer rate classes, which are billed for these costs according to a methodology set out in its application.

FortisAB proposed a methodology change and applied a point of delivery ("POD") specific allocator, to Rate 63 (Large General Service) customers to allocate the billing capacity and POD charges. For all the other rate classes, FortisAB maintained that using a three-year average of load settlement data applied across all PODs continues to be the most practical approach to develop cost allocators. The AUC approved the proposal to incorporate a POD-specific allocator for Rate 63 customers and maintain the status quo for all other customer rate classes.

Load Settlement Data

FortisAB applied an average of 2017 to 2019 load settlement data to allocate 2021 transmission access costs. The AUC directed FortisAB to update its schedules to reflect the most recent 2018 to 2020 load settlement data. The update was required as the AUC found that 2020 load settlement data would better reflect the changes in load resulting from the COVID-19 pandemic for transmission cost allocation purposes.

Line Loss Study

The AUC found it reasonable for Fortis to rely on the results of its 2010 line loss study but directed Fortis to provide an updated line loss study for all of its rate classes in its next Phase II application.

Transmission Billing Capacity

FortisAB's transmission cost allocation methodology takes into account forecast monthly billing capacity and forecast monthly energy. EQUS REA Ltd. ("EQUS") submitted that some irregularities exist for the billing capacity and energy forecast for the exterior lighting and irrigation rate classes. The AUC directed FortisAB to re-examine its forecasting methodologies for its rate classes and propose any changes to account for the irregularities for these rate classes and any other impacted rate classes in its next Phase II application.

Distribution Cost Allocation

The AUC evaluated whether FortisAB's distribution cost allocation methods provide for a just and reasonable allocation of FortisAB's distribution revenue requirement among its customer rate classes and REAs interconnected with its distribution system.

FortisAB's distribution cost allocation study relied on results obtained from FortisAB's Component Analysis Method ("CAM") model to allocate the majority of its distribution system costs. The CAM model analyzes the individual components in a distribution feeder and allocates each component (or segment of feeder) to the customers served downstream of that component. In this application, FortisAB expanded its CAM model to include all of its distribution feeders, whereas previously, its CAM model only included a sample of feeders.

Use of Customer Metering Data to Determine Customer Peak Demands Instead of Transformer Size

The CAM model does not use actual customer usage data. To further establish the accuracy of the method, FortisAB was directed to, in its next Phase II application, complete an analysis and comparison of the CAM cost allocation results on a sample of ten feeders, using actual load settlement data.

The Operation and Use of the Property Retirement Unit Multiplier Study

From information provided in an information request regarding property retirement unit multipliers, the AUC noted that the total meters of line used to calculate the estimated construction costs differed from the total amount of line used to calculate the property retirement unit costs for each rate class. FortisAB explained that the discrepancy was due to neutral conductors not being specifically delineated when determining the number of lines of each conductor configuration. The AUC directed that FortisAB correct the property retirement unit multiplier study to properly account for neutral conductors. FortisAB was directed to further examine this issue and to modify the property retirement unit multiplier study, as well as subsequently update its cost allocation study and rate calculations accordingly.

The AUC further took issue with FortisAB's indication that construction of overhead secondary conductors has similar per meter costs to that of building a line for a primary conductor. The AUC directed FortisAB to modify its property retirement unit multiplier study to add additional conductor configurations that are specific to the unit costs FortisAB incurs to construct a secondary conductor for use in the calculation of estimated construction costs and assign the appropriate quantities of a secondary conductor to these configurations for each rate class.

Sub-Functionalizing Costs Between Shared System and Local Facilities

Sub-functionalization, in the context of this application, refers to FortisAB's proposal to categorize all its distribution system components and costs into three groups (or sub-functions), which it refers to as a shared system, local facilities, and customer-related.

The AUC was not satisfied by FortisAB's sub-functionalization of asset management-related operating costs and general operating costs as 100 percent local facilities. The AUC considered that asset management-related activities should be split between shared system and local facilities and directed that FortisAB make this change in its compliance filing.

Allocation of Metering Costs

FortisAB allocated its total metering capital costs to each rate class based on the number of customers in that rate class. In this way, a residential customer with a single-phase service was allocated the same amount of metering capital costs as a three-phase large industrial customer. This is a change from previous applications as FortisAB now assumes that all meters have the same capital costs, and accordingly, the number of metered sites is used to allocate meter costs.

The AUC found that there were material differences in costs for different meter types, and noted that additional costs are required for larger services. As a result, the AUC was not persuaded that FortisAB's assumption that metering capital costs do not vary by rate class or meter type is reasonable. Accordingly, FortisAB was directed to use allocation methods similar to those of its previous Phase II applications.

Calculation and Allocation of the Farm Transmission Amounts

FortisAB submitted that it allocates its farm transmission costs to its customers and REAs as part of the costs of its distribution system. The farm transmission credits received from the Alberta Electric System Operator ("AESO") are credited to FortisAB customers annually through a Y factor provision of its PBR plan, offsetting the farm transmission costs directly borne by customers.

FortisAB last calculated its farm transmission costs and determined how to allocate the credits to customers in 2011. The AUC determined that it was preferable to use the CAM model and the allocation study to calculate farm transmission costs, as this is consistent with how FortisAB allocates all its other costs. The AUC directed FortisAB to revise its distribution cost allocation study and to update its farm transmission cost calculation.

Reallocation of Costs Between Small Capacity Rate Classes

FortisAB used its distribution cost allocation study, in combination with its CAM model, to perform most of the cost allocation study steps of functionalization, classification and allocation. The AUC found that the reallocation proposed by FortisAB more than doubled the amount of shared costs allocated to small general service customers and nearly halved the amount of shared system costs allocated to farm customers.

The AUC found that this would not result in just and reasonable rates, and it would lead to a significant and unacceptable bill impact. To set customer rates, the AUC directed that, in its compliance filing, FortisAB use the allocated costs from the CAM model without the additional cost reallocation step.

<u>Rate Design and Bill Impacts</u>

Bill Impacts and Revenue-To-Cost Ratios

In light of the extraordinary economic realities facing Alberta at the time of this decision, the AUC considered that FortisAB's bill impacts should be minimized and ideally kept to zero percent for the purposes of this decision. For the purposes of this decision, the AUC temporarily departed from its usual approach to target revenue-to-cost ratios between 95 percent and 105 percent to maintain bill predictability during this time of economic uncertainty.

The AUC noted that the timing of FortisAB's 2023 cost-of-service application could provide an opportunity for FortisAB to keep its bill impacts at or near zero for 2022 and then to adjust its rates for 2023 to move closer to the usual targeted range of 95 percent to 105 percent, keeping the rest of the methodology approved in this Phase II application the same. FortisAB was directed to address this matter in its 2023 cost-of-service application.

Customer Rate Classes

The AUC approved the request from FortisAB to split Rate 21 Farm Service into two rate schedules: Rate 21 Farm Service – Breakered Service (Closed) and Rate 22 Farm Service – Demand Metered. It further approved the requested elimination of REA Rates 24 and 29 in favour of REA Wire Owner schedules and lump sum allocation amounts for each REA Wire Owner.

The AUC denied FortisAB's proposal to eliminate Rate 32 Grain Drying Service (Closed), with the existing legacy Rate 23 customers migrated to proposed Farm Service rates (Rate 21 or 22). FortisAB's request to eliminate Rate 44 Oil & Gas (Capacity) Service (Closed), with the existing legacy Rate 44 customers being moved to Rate 45 Oil & Gas Service, was also denied.

Other Rate Design Proposed Changes

The AUC accepted changes proposed by FortisAB to transmission charges and system access services rates. The AUC determined that FortisAB's proposed transmission rate design, including introduction of a monthly peak metered demand charge is reasonable because it flows through the price signals and costs that it receives from the AESO's tariff.

Consistent with its approach of functionalizing its costs based on system, local facilities and customer cost groupings in its cost allocation study, FortisAB generally classified and designed its distribution charges based on these three cost areas. FortisAB requested approval of changes to distribution rate structures for the following Farm (Brokered Service), Irrigation Small General Service, and Oil and Gas rate classes.

The AUC found that FortisAB's proposed distribution rate design is reasonable because the proposed structure generally aligns with FortisAB's cost-of-service study, particularly with respect to sub-functionalization and classification and because, where it does not align, the AUC accepted that FortisAB was trying to minimize intra-class bill impacts. The AUC also found FortisAB's proposed weighting between fixed and variable distribution charges to be reasonable in the circumstances. The proposed changes were approved.

Billing Determinants Forecast Methodology

Given the approval of the proposed rate structure changes provided in this decision, the AUC found that FortisAB's proposed changes were necessary to contribute to billing determinant forecast accuracy and, as a result, found it is reasonable for the changes to be implemented during this PBR term. The AUC directed FortisAB to incorporate its proposed changes to its billing determinant forecast methodology according to the approved rate design changes, as well as directions related to the billing determinant method in Decision 25843-D01-2020. The AUC noted its expectation of FortisAB to use the same billing determinant forecast method in its 2022 annual PBR rate adjustment filing, as for its compliance filing to this decision.

<u>How Should the Costs Attributable to Integrated Operations with REAs be Treated in FortisAB's Distribution Tariff</u>

FortisAB's service area overlaps with the service areas of other REAs. Within an overlapping service area, FortisAB and an REA are required, under the *Roles, Relationships and Responsibilities Regulation*, *2003* ("*3R Regulation*"), to enter an IOA. As previously approved, FortisAB proposed to allocate to, but not charge, REAs for what FortisAB calculated was the REAs' share of distribution system costs resulting from its integrated operation, as identified by the CAM model.

FortisAB's Costs that are Attributable to Integrated Operations with REAs

In its cost allocation study and CAM model, FortisAB recognized that some of its assets are used, in part, to deliver energy to REA assets for use by the REAs to subsequently serve their members and vice-versa. FortisAB indicated that where its calculations needed data specific to the REAs' assets, it relied on data provided by the REA. The AUC determined that the data used by FortisAB was sufficient and of sufficient accuracy to reasonably determine the amounts allocated.

FortisAB used its CAM model in combination with its distribution cost allocation study to determine the FortisAB costs to serve REAs under integrated operations, and the REA distribution system use credit. These compose the two amounts relating to its integrated operations with REAs.

The AUC accepted the assumption that FortisAB and the REAs have similar per-unit costs for the purpose of determining the REA distribution system use credit. However, the AUC found that the usefulness of the calculated REA distribution system use credit using the CAM model is limited to a value that can be used to gauge the reasonableness of the cost allocation in this proceeding.

Are There Integrated Operations/Related Costs that Should not be Borne by FortisAB's Customers?

The AUC considered whether costs incurred by FortisAB that are related to its integrated operations with REAs and attributable to the REAs should be recovered through the distribution tariff or under the IOAs. FortisAB argued that its total revenue requirement is recoverable in its distribution tariff under Section 122 of the *Electric Utilities Act*. This includes the costs attributable to integrated operations with REAs, which were calculated to be $16.39 million in 2017.

The AUC determined that the *Electric Utilities Act* and the *3R Regulation* govern the method of REA-related costs and that it does not have the authority to approve FortisAB's costs to serve REAs under integrated operations. The AUC determined that Fortis is required to recover these costs through the mechanism set out in the *3R Regulation*, through arbitration or negotiation. These costs were required to be removed from rates charges to distribution customers.

However, the AUC found that it has the authority, and it is in the public interest, to approve the recovery of Fortis's costs related to its customers' use of the REAs' assets and systems in Fortis's distribution tariff (i.e., the REA distribution system use credit).

In determining when these costs should be removed from FortisAB's regulated revenue requirement, the AUC considered, the AUC found it reasonable to maintain FortisAB's 2017 revenue requirement for the remainder of the current PBR term. This revenue requirement had previously been approved as just and reasonable, and the two percent adjustment was not enough to require a correction.

The AUC directed FortisAB to include in its 2023 cost-of-service review application an estimate of its costs to serve REAs under integrated operations for 2023 and to remove this 2023 amount from its revenue requirement.

Terms and Conditions

FortisAB requested approval of extensive changes to its customer and retailer terms and conditions ("T&Cs") of its service. The AUC required FortisAB to provide more detail regarding the proposed section regarding the quotation package in its compliance filing to this decision. The AUC made approval of this proposed section conditional on its review of the level of detail in the compliance filing. The AUC approved, in part, amendments to the section regarding adjustment of bills in the event of a billing error.

The AUC denied the remaining amendments to FortisAB's customer T&Cs. It determined that Alberta ratepayers face exceptional circumstances in 2021, which include the current economic downturn due to the ongoing COVID-19 pandemic, the collapse in the price of oil, and the resulting significant negative impact on Albertans and businesses. The AUC considered it contrary to regulatory efficiency to approve the proposed revisions now when the T&Cs are likely to undergo additional substantive changes within the next few years due to the AUC's standardization initiative.

***FortisAlberta Inc. Code of Conduct Regulation Compliance Plan Amendments*, AUC Decision 26497-D01-2021**

Code of Conduct Compliance Plan

In this decision, the AUC approved the application from FortisAlberta Inc. ("FortisAB") to amend its Code of Conduct Compliance Plan ("Compliance Plan") subject to a change ordered by the AUC.

Pursuant to subsection 32(2) of the *Code of Conduct Regulation* ("*CCR*"), FortisAB requested approval of changes to its Compliance Plan to reflect changes introduced to the *CCR* on November 12, 2020. FortisAB sought approval of changes reflecting minor administrative changes, its recently implemented annual refresher training requirement for all employees and officers, and changes reflecting the removal and amendments to sections of the *CCR*.

The AUC found that the Compliance Plan contains no provision for the creation and retention of the records required for the AUC to carry out its future audits, as required under Section 40 of the *CCR*. Accordingly, the AUC required that FortisAB includes the following text in its Compliance Plan after the policy statement in Section 40.0 "Audit:"

- FortisAlberta Inc. will retain all code of conduct compliance records listed under Appendix A to the Compliance Plan for at least three years. The Commission may amend Appendix A from time to time on notice, and absent a registered objection, the proposed changes to the appendix will take effect within ten business days from the date of the notice.

FortisAB was further direct to amend its Compliance Plan to provide for the repeal of AUC Rule 030: *Compliance with the Code of Conduct Regulation.*

Garden Plain Wind Power Plant Connection Project, **AUC Decision 26439-D01-2021**
Electricity - Facilities

In this decision, the AUC approved a needs identification document ("NID") application from the Alberta Electric System Operator ("AESO") and facility applications from Garden Plain Wind Energy I Inc. ("Garden Plain"), ATCO Electric Ltd. ("AE") and AltaLink Management Ltd. ("AML") for the proposed Garden Plain Wind Power Plant Connection Project (the "Wind Project").

<u>Applications</u>

The applications in this proceeding sought approval of the need for and facilities required to connect the Wind Project to the Alberta Interconnected Electric System ("AIES"). Garden Plain applied for approval to construct and operate a substation required to connect the Wind Project to the AIES. Garden Plain also requested system access service ("SAS") from the AESO in response to which the AESO filed a needs application to the AUC to construct a transmission circuit to connect the substation to an existing 240-kilovolt transmission line.

AE and AML each filed facility applications requesting approval from the AUC for the specific equipment proposed to meet the need identified by the AESO. Garden Plain applied for approval to construct and operate a collector substation, where all collector lines from each wind turbine of the power plant would terminate. Garden Plain applied for a 20-MVA reactive capacitor bank but noted that the size was not yet finalized and that it would file an amendment application in this regard if a different size is required. The AUC was satisfied that Garden Plain's application met the applicable requirements.

In response to Garden Plain's request for SAS, the AESO filed a needs identification application with the AUC, pursuant to Subsection 34(1)(c) of the *Electric Utilities Act* ("*EUA*"). The AUC found that the AESO's NID contains all of the information required. As no person disputed the AESO's assessment of the need, the AUC considered the assessment of the need to be correct and approved the AESO's application.

AE applied for approval to construct and operate approximately 160 meters of 240-kV transmission line, designated to connect the proposed substation to the existing Transmission Line 9L59 ("TL-9L59"). Additionally, AE applied for permission to add a structure and a T-tap configuration to TL-9L59. AE further applied for permission to install approximately two kilometers ("km") of telecommunications fiber optic cable along Transmission Line 9LA59. AE's applications were collectively referred to as the "AE Project".

AE explained that it selected the route for the new transmission line as it is the most direct route between the connecting points and as it would avoid conflict with other infrastructure. The route of the new transmission line and of the fiber optic cable also runs within the existing right-of-way. AE stated that the AE Project is not expected to have adverse environmental effects and committed to comply with the environmental protection plan and with any direction provided by Alberta Environment and Parks. The AUC determined that the application meets all applicable requirements of the *HEEA* and Rule 007.

AML filed an application for approval to construct and operate a four-km underground fiber optic cable to support the connection of the Wind Project to the grid. This serves to enable active monitoring of the grid and to ensure safe and reliable operation. AML also applied to modify existing and install new protection and control, supervisory control and data acquisition ("SCADA"), and telecommunications equipment at three existing substations and to install new telecommunications equipment inside the existing control building at its Oakland 946S Substation. The need for this equipment was outlined in the AESO's needs application.

The AUC determined that the application met the requirements of the *HEEA* and Rule 007. The AUC further noted that AE's proposed routing of the fiber optic cable within existing road allowances and requires no additional right-of-way and minimizes possible adverse environmental effects. The AUC found that approval of all applications subject to this proceeding is in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act.*

***Lathom Solar GP Ltd. Lathom Solar Project,* AUC Decision 26538-D01-2021**
Solar – Facilities

In this decision, the AUC approved an application from Lathom Solar LP, on behalf of its general partner Lathom Solar GP Ltd. ("Lathom Solar") for permission to construct and operate the Lathom Solar Project (the "Project").

<u>Applications</u>

The Project consists of a 120-megawatt solar Power Plant and an associated substation in the County of Newell. The Project and the substation will be located on agricultural land. The Project consists of approximately 340,000 bi-facial solar panels, 38 inverter and transformer stations, a 34.5-kilovolt underground collector system and a collector substation.

The Project will connect to an existing AltaLink Management Ltd. transmission line in the area. The Project is expected to come into service in December 2022, with construction beginning in April of 2022.

<u>AUC Findings</u>

As Lathom Solar submitted that it had not yet finalized the design or equipment of the Project, the AUC, as a condition for approval, required Lathom Solar to file a letter to the AUC that identifies the make, model, and quantity of the equipment and the final equipment layout, no later than one month before beginning construction.

To ensure that the nearby dwelling and Highway 1 would experience no glare, the AUC required that anti-reflective coating be used on the Project solar panels. Further, regarding solar glare, the AUC noted that there are limitations to the solar glare assessment modeling due to the backtracking functionality of the proposed solar panel tracking system. To provide for issues resulting from these uncertainties, the AUC required Lathom Solar to 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 Lathom Solar's response to the complaints and concerns.

As required by Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants* Lathom Solar, the approval holder is further required to submit an annual post-construction monitoring survey report to AEP and the AUC. This report is to be filed within 13 months of the Project becoming operational.

The AUC considered the Project to be in the public interest. Lathom Solar's application for construction and operation of the Lathom Solar Project and the application to construct and operate the associated substation was approved.

***Neyaskweyahk Sundancer GP Ltd. Neyaskweyahk Sundancer Solar Project Phase 2 Expansion,* AUC Decision 26372-D01-2021**
Solar – Facilities

In this decision, the AUC approved an application from Neyaskweyahk Sundancer GP Ltd. (“Neyaskweyahk”) to construct an expansion of the existing Neyaskweyahk Sundancer Solar Project (the “Project”), operate the expanded project, and connect the expanded project to the FortisAlberta Inc. distribution system.

Application

Neyaskweyahk applied for permission to expand the Project, located on federal reserve lands within the Ermineskin Cree Nation, from 0.99 megawatts (“MW”) to 2 MW. The expansion is expected to be in service by December 7, 2021, with construction starting in the summer of 2021.

The first phase of the Project had been designated as a community generating unit and qualified as a small power plant in Decision 25626-D01-2020. With this expansion, the Project would no longer qualify as a small power plant within the meaning of Subsection 18.1(1) of the *Hydro and Electric Energy Regulation*. The Project consequently required a power plant approval and connection order.

Accordingly, Neyaskweyahk’s application included a participant involvement program (“PIP”), noise impact assessment, and solar glare hazard analysis considering the combined impacts of both phases of the Project. Neyaskweyahk also submitted a wildlife field reconnaissance memo in respect of the existing phase and an environmental review report prepared in respect of this expansion.

AUC Findings

The AUC determined that the application met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. The AUC noted that no issues were raised after stakeholders located within 1,500 meters of the Project boundary were notified as part of the PIP, and a meeting with two Elders from the community was held to discuss the historical use of the land and any special considerations for the Project. The AUC further noted its expectation of Neyaskweyahk to acquire the necessary Indigenous Services Canada authorization and Band Council Resolution before proceeding with construction of the Project.

For the Project’s decommissioning and final reclamation monitoring, Neyaskweyahk committed to following the requirements of Indigenous Services Canada or any updated standards in place at the relevant time.

The AUC accepted the glare hazard analysis submitted. However, it noted its expectation that any glare issues associated with the Project will be addressed by Neyaskweyahk in a timely manner. As conditions of approval, the AUC required that Neyaskweyahk use an anti-reflective coating on the solar panels of the expansion and that a report describing complaints or concerns received regarding solar glare from the Project during expansion’s first year of operation, as well as its response to the complaints or concerns.

As final equipment specifications may change as a result of detailed engineering progresses, the AUC also required that Neyaskweyahk submit a letter with the AUC noting the details of the selected equipment and confirming that the final design does not change the details of the Project noted in this application. This letter is to be filed once the equipment has been selected and no later than one month before the scheduled start of construction.

The AUC was satisfied that the expansion would not result in changes to the community generating status of the power plant. The AUC approved the application to construct and operate the Project, and to connect it to the FortisAlberta Inc. distribution system. The approvals will be issued to Neyaskweyahk Sundancer GP Ltd. in its capacity as general partner of Neyaskweyahk Sundancer LP.

***Siemens Energy Canada Limited Acme Generating Station*, 26478-D01-2021**
Facilities - Generating Station

In this decision, the AUC approved an application from Siemens Energy Canada ("Siemens") to construct, operate, and connect a 9.5-megawatt ("MW") compressor station waste heat recovery power plant eight kilometres from the town of Beiseker in the west half of Section 19, Township 28, Range 26, designated as the Acme Generating Station.

The project would be located within the existing Foothills Pipe Lines (Alta.) Ltd. Acme natural gas compressor station 363, adjacent to agricultural land and be connected to the FortisAlberta Inc. electric distribution system.

The AUC found that the project met the requirements of Rule 007 and Rule 012. An air quality assessment for the site found that the proposed waste heat recovery plant will likely reduce air emissions from the existing compressor station but may increase the annual NO_2 slightly. The AUC found that the increase falls within the accuracy uncertainty of the analysis and the predicted emissions are compliant with the Alberta Ambient Air Quality Objectives.

Siemens provided correspondence from Alberta Environment and Parks ("AEP") that stated no environment impact assessments were required for the project since it would not require disturbance of any natural environment. Siemens stated that it would submit an *Environmental Protection and Enhancement Act* industrial approval application to AEP later in 2021. This was accepted by the AUC.

Finally, a letter of non-objection was provided to the AUC from FortisAlberta confirming that it is prepared to allow the interconnection of the power plant to its 25-kilovolt distribution system.

Syncrude Canada Ltd. Transfer of Licences to Suncor Energy Operating Inc., AUC Decision 26614-D01-2021
Facilities - Permits

In this decision, the AUC approved transferring the licenses to operate four transmission lines and two substations from Syncrude Canada Ltd. ("Syncrude") to Suncor Energy Operating Inc. ("SESOI"). The AUC saw no need to consider approving the applied-for transfer of permits to construct the transmission facilities as they had already been constructed, and no additional facilities were proposed.

<u>Discussion</u>

Syncrude operates an electric system, which has been designated an industrial system, to provide electricity to its oilsands operations (Mildred Lake Plant and Aurora mines) in the Athabasca Oil Sands Region (collectively known as the "Syncrude Project"). Syncrude applied to transfer five permits and licenses associated with the Syncrude Project to SESOI.

Syncrude stated that SESOI, which is a wholly owned subsidiary of Suncor Energy Inc., was incorporated for the purpose of assuming the role of operator of the Syncrude Project. Syncrude confirmed that the transmission facilities will continue to service the Syncrude Project and that the proposed transfers do not involve any changes to the facilities.

<u>AUC Findings</u>

As all the transmission lines to which the permits and licenses of this application pertain are already built, there was no need to transfer permits to construct the facilities. The AUC, accordingly, only considered the transfer of licenses to operate the facilities. Following a review of the application, the AUC accepted that there were no unresolved public or industry objections or concerns regarding the application for transfer.

Syncrude stated that the proposed transfer does not involve any changes to the existing facilities and is only required to authorize SESOI to operate the transmission facilities proposed for transfer, which will continue serving the Syncrude Project as they have in the past. The AUC was satisfied that the requested transfer would have no effect on previously considered social, economic and environmental effects of the transmission facilities to be transferred to SESOI's operatorship. The AUC was also satisfied that that SESOI meets the requirements of Section 23 of the *Hydro and Electric Energy Act* and is eligible to hold the licenses that are currently issued to Syncrude.

The AUC found the transfer of the licenses to be in the public interest. The AUC will issue new licenses to operate the transmission facilities to SESOI once it receives written confirmation from Syncrude Canada Ltd. of the precise date that the transfer of operatorship of the Syncrude Project to SESOI is to become effective.

CANADA ENERGY REGULATOR

***Kingston Midstream Westspur Limited Secure Energy Services Inc. Application for Service and Suitable and Adequate Interconnection Facilities on the Westspur Pipeline*, RH-003-2020**

Construction of Adequate and Suitable Facilities - Unjust Discrimination

In this decision the Canada Energy Regulator ("CER") directed Kingston Midstream Westspur Limited ("Kinsgston") to provide adequate and suitable facilities to allow Secure Energy Services Inc. ("Secure") to receive crude oil from, and deliver crude oil to, the Westspur Pipeline owned by Kingston.

Background

Kingston is regulated by the CER as a Group 2 company and is the current owner and operator of the Westspur Pipeline. Currently product of the same crude type shipped on Westspur Pipeline is not batched or segregated. In June 2017, Crescent Point Energy ("Crescent Point") filed a complaint with the National Energy Board ("NEB") regarding operational practices on the Westspur Pipeline, then owned and operated by TEML Westspur Pipelines Limited. In 2019, a settlement agreement was reached among Tundra Energy Marking Limited ("TEML") affiliates including TEML Westspur, and eight producers (the "Settlement Agreement"). As a result of the Settlement Agreement, Crescent Point withdrew its complaint. The Settlement Agreement was not filed with, or approved by, the NEB.

Since June 2016, Secure has owned and operated the Secure Alida Terminal. The Secure Alida Terminal is connected to the Kingston-owned Alida Terminal, which is approximately 350 metres from the Secure Alida Terminal, via two provincially regulated pipelines and related infrastructure. Secure was given notice to that the interconnection agreement to deliver crude oil to and from the Secure Alida Terminal was being terminated. Secure was effectively prohibited from delivering blended oil from the Secure Alida Terminal. For a while, Secure continued to operate at the Secure Alida Terminal by not passing the Saskatchewan System toll through to its customers but eventually had to, which resulted in Secure's customers ceasing their deliveries to the Secure Alida Terminal, and Secure having to lay off staff and shut down the Secure Alida Terminal.

Service on the Westspur Pipeline Under Subsection 239(1) of the CER Act

Directing the Provision of Service to Secure

The CER held that a key principle that applies to Kingston is that a company operating an oil pipeline is under a *prima facie* duty to ship all oil tendered to it unless it can convince the CER that for some reason it cannot. Kingston presented evidence and arguments in support of its position that the denial of service to Secure is reasonable, not unjustly discriminatory and in the public interest. The CER found the submissions and arguments made to be, collectively and individually, unpersuasive and lacking in convincing evidence to give rise to reasons to restrict access to a common carrier pipeline.

The CER considered need and market interest, the potential effect on the Settlement Agreement, the impact on the quality of the crude steam and unjust discrimination. In respect of unjust discrimination the CER held that Section 235 of the *Canadian Energy Regulator Act* ("*CER Act*") prohibits "unjust discrimination in tolls, service or facilities against any person or locality". Together with subsection 239(1), this section requires that an oil pipeline offer service under the same terms and conditions to any party wishing to ship oil on its line. If it is shown that Kingston discriminated, the burden lies on Kingston to prove that the discrimination was not unjust.

The CER was of the view that the receipt and delivery points requested by Secure are similar to the receipt and delivery points that were provided to Kingston Marketing for the Manitoba Interconnect Westspur ("MIW") facility. The CER found that Kingston discriminated against Secure by denying Secure's requested service. Kingston argued that Kingston Marketing's commercial arrangements (i.e., the Settlement Agreement and lease and in-stream purchases from shippers) put it in fundamentally different circumstances from Secure. The CER was of the view that these private commercial arrangements do not justify discrimination.

Market Power

The CER found that in addition to addressing the specific relief requested by Secure, as a regulator, the CER must ensure that there is appropriate regulatory oversight of the Westspur Pipeline. This includes preventing the abuse of market power. The CER was of the view that, particularly in the case of a Group 2 company regulated on a complaint-basis, as Kingston has been to date, the CER should inquire and respond in a fulsome manner when a shipper or other interested party tenders evidence that gives rise to a reasonable perception of the abuse of market power. The CER must address this perception of market power to ensure the presumption - which exists in the context of Group 2 companies absent a complaint - that tolls are just and reasonable remains valid. The CER found that directing Kingston to provide delivery and receipt service to the Secure Alida Terminal addresses the perceived abuse of market power in the circumstances of this application.

Adequate and Suitable Facilities Under Subsection 239(3) of the *CER Act*

The CER explained that its authority under subsection 239(3) of the *CER Act* to require a company to provide adequate and suitable facilities is considered an extraordinary power. Before issuing such an order, the CER must consider if there would be an undue burden on the company. The onus was on Secure to meet the test under subsection 239(3) of the *CER Act*.

Existing Facilities

Existing facilities connect the Secure Alida Terminal to the CER regulated Kingston Alida Terminal. Kingston insisted that the existing facilities were not available to facilitate Secure's access to the Westspur Pipeline. All attempts by Secure to negotiate access have been unsuccessful. This required the CER to consider whether to require Kingston to construct new facilities in order to allow Secure access to the Westspur Pipeline for common carrier receipt and delivery services. The CER was of the view that, in the absence of an agreement to purchase, transfer, or use the existing facilities, the construction of new connection facilities is appropriate and granted the relief sought by Secure. While the CER was mindful that requiring an extension of pipeline facilities is extraordinary, based on the facts of this case, it held that it was a solution that must be allowed.

Facilities Required to Provide Adequate and Suitable Connections

In considering whether an extension of facilities should be ordered it is necessary to consider the type of facilities that would be required. The CER found that must also consider whether batching and segregation of Secure’s product is required. The CER found that the service Secure has requested and the quality of oil it proposes to deliver to the Westspur Pipeline are permitted by the Westspur Tariff. The CER was not convinced that the geographical location of existing facilities, which previously operated at the same time without issue, justified the imposition of any restrictions or additional facilities requirements on Secure. The CER held that batching facilities are not needed to provide service to Secure as requiring batching would be unjustly discriminatory.

Need and Public Interest

The CER must consider whether requiring Kingston to provide an extension of facilities is necessary or in the public interest. In this case, regardless of whether need is considered separately from public interest, the result would be the same. The onus was on Secure to demonstrate that connections are necessary or in the public interest. The CER found that Secure demonstrated that it needs receipt and delivery connections to the Westspur Pipeline for the operation of its Secure Alida Terminal and that overall, the requested connection facilities are in the public interest as it is in the public interest to allow competition.

Undue Burden

The CER held that consideration of the public interest alone is not sufficient to grant the relief of an extension of facilities as the CER must also consider whether there is an undue burden on Kingston. This must be considered and balanced against public interest considerations. The CER found that there is no undue burden on Kingston from being ordered to provide new facilities as Secure agreed to pay the reasonable costs in that regard.

Tolls for Requested Service

The CER found that the toll between the MIW and the Westspur Pipeline, currently $0.10/m^3, provides an upper cap for the potentially just and reasonable and not unjustly discriminatory toll for the interconnection between the Secure Alida Terminal and the Westspur Pipeline and therefore, approved a toll of $0.10/m^3.

Like any other shipper, Secure would be subject to the tolls and terms and conditions of service specified in the CER tariff filed by Kingston for the Westspur Pipeline. The CER found that Secure has demonstrated that it would be discriminatory for Kingston to require Secure to enter into a take-or-pay agreement as there is no requirement for a take-or-pay agreement in the Westspur Tariff. The CER agreed with Secure's submission that the terms and conditions of access to a pipeline must be reflected in the applicable tariff in order to comply with the open access principle.

The CER held that the mechanism for rolling in capital costs to the rate base is clear when a pipeline operates under a cost-of-service toll methodology. The mechanism for rolling in capital costs is unclear when market-based rates are used, as in this case. The CER accepted the argument from Crescent Point that costs in this case should be borne by the user as this is supported by the principle of cost causation.

Terms of Service

The terms of service for a pipeline are set out in its tariff, as defined in section 225 of the *CER Act.* Secure, as a part of its requested relief, asked that the CER prescribe terms for the Alida Delivery and the Alida Receipt pursuant to section 226 of the *CER Act*, including service on terms that are not unjustly discriminatory and consistent with Kingston's published tariff for the Westspur Pipeline. As set out in section 235 of the *CER Act*, Kingston, as the pipeline company, must not make any unjust discrimination in tolls, service or facilities against any person or locality.

The CER found that the requested service is permitted under the Westspur Tariff. Adding the service as requested by Secure was consistent with common carriage requirements. The CER therefore directed Kingston to file an updated Westspur Tariff with Secure's Alida Terminal listed as a receipt and delivery point in a timely manner in advance of the connection facilities being operational. The CER noted that it is generally supportive of parties resolving or reaching settlement agreements as long as those agreements do not negatively impact statutory obligations. All terms and conditions of access to a pipeline must be reflected in a public tariff. Otherwise, such terms and conditions, even if negotiated, cannot be relied on.

Regulatory Oversight and Disposition

Throughout the hearing, a number of issues were raised regarding Kingston's conduct and the Settlement Agreement. In addition to the CER's authority to grant the specific relief requested by Secure, the CER has authority in the broadest possible terms under the *CER Act* to ensure that there is appropriate regulatory oversight of the Westspur Pipeline. Section 226 of the *CER Act* provides that the CER may make orders with respect to all matters relating to traffic, tolls and tariffs. The CER may also inquire into any matter under the *CER Act* and the CER may conduct compliance audits.

The CER was of the view that these concerns support the potential need for further regulatory oversight over Kingston and the Westspur Pipeline. The CER reminded Kingston that all pipeline companies are expected to comply with the *CER Act,* applicable regulations, and decisions, orders, and directives of the CER. Kingston must provide shippers with enough information regarding tolls and tariffs to enable them to determine whether a complaint is warranted. There may also be shippers without the resources to make a complaint and the regulation of Group 2 companies relies on the CER being able to review service and tolling issues for the benefit of all interested parties.

The CER therefore directed Kingston to file comments with the CER as to whether it should be regulated as a Group 1 or Group 2 company. Kingston was further directed to provide any reasons it believes it should continue to be regulated as a Group 2 company. The CER also recommended a financial regulatory audit of Kingston.