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 Laura-Marie Berg, Marlé Riley or Rosa Twyman.

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*.*

You can also subscribe to our YouTube Channel to view this issue of the Energy Regulatory Report in 5 Minutes.

IN THIS ISSUE:

ALBERTA ENERGY REGULATOR

Coal Activity on Category 2 Land Suspended, AER Bulletin 2021-19

Coal Exploration

On April 23, 2021, the Government of Alberta issued *Ministerial Order 093/2021*. On May 11, 2021, the AER posted Bulletin 2021-19 announcing that this order directs the AER to take steps to suspend all approvals for coal exploration activities on Category 2 land until December 31, 2021, or such other date specified in writing by the Minister of Energy. The 1976 coal development policy currently in effect for Alberta divides provincial land into four numbered categories, with Category 1 being the most restricted. Category 2 lands are found along the eastern slopes of the Rocky Mountains.

Changes to the Mine Financial Security Program Guide, AER Bulletin 2021-20

Mine Approvals

On May 6, 2021, Alberta Environment and Parks updated the Mine Financial Security Program Standard. The update allows the AER to permit mine approval holders to use an alternative methodology to calculate their mine financial security requirements. The AER amended the *Guide to the Mine Financial Security Program* to reflect this change. The updated materials are available on the AER website under the Regulating Development section.

ALBERTA UTILITIES COMMISSION

Amendments to AUC Rule 001, AUC Bulletin 2021-10

Rates Proceedings - Efficiency

On April 27, 2021, the AUC approved amendments to Rule 001: *Rules of Practice* applicable to proceedings registered on or after May 17, 2021.

In 2020 the AUC accepted 29 of the recommendations of the *Report of the AUC Procedures and Process Review Committee* to support the AUC in its drive to increase efficiency and reduce regulatory lag in how it deals with utility rate applications.

The amendments to Rule 001 uphold the AUC's commitment to adjudicative efficiency. At the same time, the changes recognize that the AUC already has broad authority to case manage its proceedings assertively. The amendments are targeted at codifying standard procedures and the AUC's expectations of parties to promote regulatory efficiency without altering the AUC's discretion to control its processes. Notably, the amendments support the efficient scoping and scheduling of proceedings through the early establishment of issue lists and process schedules.

Amendments to AUC Rule 016, AUC Bulletin 2021-11

Review and Variance - Efficiency

The AUC has amended Rule 016: *Review of Commission Decisions* as part of its continuous effort to implement process efficiencies identified in the *Report of the AUC Procedures and Processes Review Committee*. Rule 016 sets out the process applied when the AUC exercises its discretionary authority to review its own decisions, on its initiative or at the request of a party. The AUC amended Rule 016 to clarify the circumstances in which a review will be considered and enhance the review process's efficiency.

Rule 016 was amended to:

- Remove from the scope of the AUC review errors of law or jurisdiction;
- Change the filing deadline for review and variance applications to 30 days after the original decision is issued; and
- Introduce page limits for applications and reply submissions.

The AUC acknowledged the concern raised by stakeholders that removing errors of law or jurisdiction from the scope could make way for complexities. The AUC clarified that the proposed revisions are designed to minimize overlap with Court of Appeal of Alberta proceedings based on the nature of the question under review or appeal. The AUC recognized that questions might have to be assessed on a case-by-case basis to determine the nature of the alleged error. The AUC determined that undertaking such an assessment at the start of a proceeding will promote efficiency in the review process for all parties.

Regarding the other amendments, the AUC received comments that the proposed page limits may not be enough in some cases to allow a full explanation of a position. The complexity of a position taken by a party and the nature of the decision under review may, in individual cases, not be shortened to the proposed page limit. In response to the comments, the AUC increased the page limits initially proposed. Parties can seek approval from the AUC to expand these page limits further. Further minor changes were made to the wording to improve clarity and remove information requirements that were already satisfied by parties' use of the eFiling System.

***AltaLink Management Ltd. 2019 Deferral Account Reconciliation Filing to Decision 25913-D01-2021 and Decision 26278-D01-2021,* AUC Decision 26500-D01-2021**
Rates - Compliance Filing

This decision set out the AUC's findings on AltaLink Management Ltd.'s ("AML") 's 2019 projects deferral account reconciliation ("DACDA") compliance application related to Decision 25913-D01-2021 and Decision 26278-D01-2021. The AUC also approved AML's proposal to dispose of its final settlement balances for 2019 of $2.6 million through a one-time billing of the Alberta Electric System Operator ("AESO") as filed.

Introduction

In Decision 25913-D01-2021, AML was directed to identify any findings related to the Proceeding 26278 decision, AML's 2016-2018 DACDA, that apply to its 2019 DACDA and to true-up any impact as part of either a separate compliance application or as part of its next general tariff application ("GTA"). Shortly after the AUC issued Decision 26278-D01-2021, AML filed an update to its current application.

Findings

The AUC was satisfied that AML's compliance filing adequately addressed and responded to directions issued in Decision 25913-D01-2021.

In Decision 25913-D01-2021, the AUC found that not all of the expenditures related to the ATCO Jasper Project were prudently incurred. Accordingly, in Direction 3, AML was required to reduce its total requested capital additions to December 31, 2019, by $465,035. The AUC determined that AML had complied with this direction by removing $465,035 from the ATCO Jasper actual additions.

Direction 4 required AML to file an application complying with the directions and disallowances made in Decision 25913 either as part of a separate compliance application or as part of its next GTA. The AUC found that the requested true-up amount provided in AML's revised reconciliation and its explanation that it is not seeking approval of the payment of interest pursuant to Rule 023: *Rules Respecting Payment of Interest* complied with Direction 4 of Decision 25913-D01-2021.

Decision 25913-D01-2021 was issued while Proceeding 26278 was still ongoing. As Proceeding 26278 was predicted to impact Decision 25913-D01-2021, Direction 5 required AML to identify any findings related to the Proceeding 26278 decision applicable to its 2019 DACDA and to true-up any impact as part of either a separate compliance application or as part of its next GTA. The AUC found that AML properly identified the implications of Decision 26278-D01-2021 on the 2019 DACDA.

The AUC found that AML had properly applied a reduction to 2019 trailing costs of three projects in compliance with Direction 1 of Decision 26278-D01-2021 regarding the disallowance of a portion of DACDA support costs. The AUC also found AML's explanation that adjustments to the rate base for disallowances will be reflected in its upcoming 2022-2023 GTA was reasonable.

Concerning Direction 2 from Decision 26278-D01-2021, the AUC accepted AML's explanation that the costs incurred in 2019 for the 2016-2018 DACDA were charged to the relevant 2016-2018 projects and are included in trailing costs in the 2019 DACDA.

Based on the above, the AUC approved AML's proposal to dispose of its final settlement balances for 2019 of $2.6 million through a one-time billing to the AESO.

***AltaLink Management Ltd. Transmission Line 225L Rebuild,* AUC Decision 26325-D01-2021**
Facilities - Electricity

In this decision, the AUC approved the application from AltaLink Management Ltd. ("AML") to alter portions of the existing Transmission Line 225L in the Magrath Area.

Application

As part of AML's capital upgrade program, AML is rebuilding a 22 kilometer ("km") section of the 69-kilovolt ("kV") Transmission Line 225L. AML classified the majority of the rebuild as "like-for-like" with less than a five-meter shift to the centreline of the transmission line. There were four segments classified as needing relocations that would not be categorized as "like-for-like". In addition to those four segments, portions of the Transmission Line 225L are currently located adjacent to the Highway 5 right-of-way on private lands. AML requested approval to relocate the four segments and shift sections of the transmission line from private lands onto the Highway 5 right-of-way.

AML submitted that three of the proposed relocation segments were requested by landowners, and the fourth proposed relocation is an opportunity to improve the alignment of the transmission line following a consultation with the Town of Magrath and Alberta Transportation.

AUC Findings

The AUC found that the application had met the information requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. The AUC was also satisfied that approval of the project would be in the public interest having regard to the social, economic, and other effects of the project, including its effect on the environment.

As the replacement involved removal of the transmission line from cultivated fields and private lands onto the Highway 5 right-of-way, the AUC found that the proposed alteration would result in a reduced impact to the area by Transmission Line 225L. AML indicated that the Town of Magrath and Alberta Transportation are in support of the section closest to Magrath, and the potentially affected stakeholders had no outstanding concerns.

AML indicated that it would upgrade the transmission line to 138-kV. However, the transmission line would remain energized at 69-kV for the foreseeable future. The use of 138-kV structures would enable AML to minimize inventory and standardize spare parts, and it would allow for an upgrade to a 138-kV conductor without the need to replace the structures if directed in the future.

The AUC agreed that the construction of the 138-kV transmission line structures is prudent. It noted that these structures meet the aviation safe structure design guidelines, provide efficiency by standardizing transmission lines, and could provide cost savings in the case of a transmission line upgrade.

Regarding the environmental evaluation that indicated that the project area has numerous temporary wetlands and historical occurrences of sensitive wildlife, the AUC was satisfied that the measures the AUC would implement would reduce the environmental impact to a negligible level. The project is along an existing road, mainly next to agricultural land, and is a rebuild of an existing transmission line. AML would also comply with the *Code of Practice Notification for Powerline Works Impacting Wetlands*, apply for reclamation certificates, and conduct site-specific wildlife surveys as required by Alberta Environment and Parks.

***AMAR Developments Ltd. Decision on Preliminary Question Application for Review of Decision 25519-D02-2021 Final Water Rates for Cambridge Park Estates,* AUC Decision 26429-D01-2021**
Review and Variance - Preliminary Question

In this decision, the AUC allowed the application filed by AMAR Developments Ltd. ("AMAR") requesting a review and variance of specific findings in AUC Decision 25591-D02-2021 (the "Decision"). On a final basis, the Decision approved rates effective March 1, 2021, including a fixed rate, variable charge, and supplemental variable charge. In varying the findings from that decision, the AUC established a variable charge of $4.951/m^3 effective June 1, 2021.

Issues

In its review application, AMAR alleged the following errors:

- The calculation of over-collected amounts for May-December 2020 unfairly prejudices AMAR as the AUC used two different methodologies.

- The AUC erroneously determined that its averaging of the 2020 approved revenue requirement (and billing determinants) over 12 months was fair to both Customers and AMAR.

- The final rate of $3.495/m^3 determined in the Decision to be in effect as of March 1, 2021, will result in large financial losses for AMAR during 2021.

- The AUC decisions and determinations failed to recognize that AMAR will be unable to recover these losses in subsequent years as the water distribution system will be taken over by Rocky View County at or near the end of 2021.

The review panel determined that, in brief, the issues raised by AMAR is the hearing panel assessed 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. This method underestimated the costs that would be incurred between May and December 2020. In its application, AMAR requested a variance of the Decision such that the same time period is used for assessing both the costs and revenue requirement in the calculation of the variable rate.

AMAR proposed a methodology that bases the calculation of overcollection on the actual revenue requirements and collected revenues from May 1, 2020, to December 31, 2020.

The interveners took issue with AMAR's claim that it will not recover its losses in future years due to the expected transfer of its distribution system to Rocky View County later in 2021. However, the review panel agreed with AMAR that the system transfer is not relevant and noted that in Decision 25519-D02-2021, the hearing panel approved water rates for 2022 if the pipeline is delayed or Rocky View County does not assume operations prior to 2022.

Decision

Stage 1 - Is There an Error on the Face of the Decision or That Otherwise Exists on a Balance of Probabilities

The review panel determined that AMAR demonstrated that an error is obvious on the face of the Decision or otherwise exists on a balance of probabilities. The review panel determined that the method used to calculate the variable rate could lead the review panel to materially vary the findings in the Decision regarding the variable rate.

The review panel agreed with AMAR that the methodology used to determine the 2021 variable charge was incorrect. By averaging the revenue requirement over 12 months, the methodology failed to consider the higher water hauling costs during the periods of higher usage that occur in the summer and fall. The review panel agreed with AMAR that these higher costs in the summer and fall were the main driver of its interim rates approved effective July 1, 2020, in Decision 25519-D01-2020. The variable rate calculated in that Decision would have considered the seasonality of such costs, while the final rate determined in Decision 25519-D02-2021 did not. The review panel found that by averaging the 2020 revenue requirement over 12 months, AMAR could not recover the full revenue requirement from May 1, 2020, to December 31, 2020.

Stage 2 – Should the Decision be Confirmed Rescinded or Varied?

The review panel found that the 2020 revenue requirement should be based on the actual revenue requirements from May 1, 2020, to December 31, 2020, and that the Decision should be varied accordingly. The review panel found that the updated calculations provided by AMAR in its reply submission and the resulting 2021 variable charge of $4.951/m^3 accurately reflect this change. The review panel approved a revised variable charge of $4.951/m^3, and it varied the Decision accordingly.

ENMAX Energy Corporation 2021 Regulated Rate Option Non-Energy Tariff, AUC Decision 25949-D02-2021

Interim Rates - RRO Non-Energy

In this decision, the AUC approved ENMAX Energy Corporation's ("EEC") 's regulated rate option ("RRO") non-energy charges for 2021.

The AUC approved a COVID-19 deferral account for EEC's bad debt expenses, RRO site counts, final notice fees, and late payment charges. Considering the effects of the pandemic and financial situation that has been imposed on many customers, the AUC noted its goal to avoid rate increases and keep rates stable for customers. Given the approval of a deferral account for EEC's bad debt expense, the AUC would keep rates stable for 2021 by approving an adjusted forecast for EEC's 2021 bad debt expense.

The AUC denied EEC's proposal to change how billing and customer care ("B&CC") costs are allocated. Also, it disallowed the proposed increase to shared services costs and a proposed cost increase resulting from the movement of EEC's RRO operations from ENMAX Power Corporation ("EPC") to EEC.

The AUC approved a non-labour escalation factor of 1.8 per cent and a 0.0 per cent salary escalation factor for both bargaining unit and management and profession employees; final 2021 non-energy rates of $0.2201 per day for residential customers, and $0.1975 per day for small commercial customers, subject to any adjustments necessary for disposition of the COVID-19 deferral account.

Issues Examined in This Decision

COVID-19 Deferral Account

(a) Request for Deferral Account Treatment for Bad Debt Expense

EEC requested a forecast bad debt expense of $4.5 million for 2021, more than double the approved bad debt forecasts for 2019 and 2020. EEC submitted that deferral account treatment of bad debt expense would protect both EEC and its customers from the risk of over-or under-recovery of bad debt expense due to the pandemic.

The AUC agreed with EEC that there is no consensus on when the economic conditions will recover from the economic downturn. The AUC noted that on the balance of the evidence provided, it was difficult to determine with any precision a reasonable bad debt expense forecast for 2021. The AUC found that the increased bad debt is directly related to the COVID-19 pandemic and that the effects of the pandemic are beyond EEC's control. The AUC approved deferral account treatment for EEC's 2021 bad debt expense.

(b) Request for Deferral Account Treatment for Site Counts

EEC proposed to include its 2021 forecast RRO site count in its COVID-19 deferral account. Following an information request from the AUC, EEC provided updated site counts and a comparison of those updated numbers to its original forecasts. EEC stated that there was a less aggressive downward trend in RRO sites compared to the original forecast.

The AUC found that the information provided by EEC shows that the rate of decline in RRO site counts was impacted by the COVID-19 pandemic and health measures implemented in Alberta. The AUC approved the inclusion of RRO site counts in the COVID-19 deferral account for the purpose of calculating the daily administration charge.

(c) Request for Deferral Account Treatment for Other Cost Items

EEC proposed to include administration costs and call center costs in its COVID-19 deferral account. The AUC found that EEC had not clearly explained what the noted costs include. The proposal to include administration costs and call center costs failed the deferral account test of materiality, uncertainty or difficulty in forecasting, and

the direct relation of incremental costs to the COVID-19 pandemic. The AUC denied EEC's proposal to include administration costs and call center costs in its COVID-19 deferral account.

EEC also proposed that if it identifies other cost categories that are materially affected by the pandemic, it may apply to include those costs in the deferral account when the deferral account is reconciled. The AUC denied this proposal, noting that the only items that may be included in EEC's 2021 COVID-19 deferral account are those that are approved in this decision.

(d) Restricting the COVID-19 Deferral Account to Only Pre-Existing RRO Customers

The Office of the Utilities Consumer Advocate ("UCA") and InterGroup expressed concerns with the possibility that deferral account treatment for bad debt could create an incentive for EEC's competitive retailer to drop sites to the RRO.

The AUC found that there was not enough evidence to support either the UCA's premise or EEC's position supporting the contrary. The AUC accordingly dismissed the UCA's argument in this regard. However, the AUC noted its interest in exploring the statistics further in a future proceeding, relating to the number of customers dropped by EEC's competitive retailer and taken up by EEC's RRO during various time periods and economic circumstances. The AUC directed EEC to provide evidence on these statistics in its next RRO non-energy tariff application.

(e) Disposition of COVID-19 Deferral Account

EEC stated that it would apply for the disposition of its 2021 COVID-19 deferral account "once the disruption caused by the pandemic is materially reduced, and actual costs are available and have been finalized." The AUC agreed with concerns raised by interveners that basing the disposition of the deferral account on a material reduction in the disruption caused by the pandemic unnecessarily creates significant uncertainty for customers and the AUC. The AUC directed EEC to file for disposition of its COVID-19 deferral account once it has actual site count and bad debt figures for 2021.

Bad Debt Expense

The AUC repeated that there was no consensus at the time of this decision on when economic conditions would recover. This makes it difficult to determine a reasonable forecast for EEC's 2021 bad debt expense. The AUC denied EEC's requested increase in its forecast for bad debt expense, subject to the finalization of bad debt expense in the disposition of the COVID-19 deferral account in a future application.

Billing and Customer Care Allocation

ENMAX proposed changes to the primary and secondary allocators for B&CC revenue cycle operations for the subfunctions of revenue cycle operations, bill production, and payment and collections costs (third party and fees). The proposed changes to EEC's B&CC allocation methodology result in an increase in B&CC costs allocated to the RRO from $8.3 million to $9.2 million.

The AUC assesses an allocation method to ensure that it allocated costs accurately and does not shift costs to regulated customers. Accordingly, the AUC was not prepared to approve piecemeal changes to the B&CC methodology that result in costs of approximately $900,000 allocated to the RRO. The AUC denied EEC's proposal to adopt new cost allocators for B&CC costs for 2021 and directed EEC to file B&CC cost forecasts determined using the existing methodology as part of its application for disposition of the COVID-19 deferral account.

Corporate and Shared Services Costs

Shared services costs are costs charged by ENMAX Corporation to its various business units, including EEC as the RRO provider. For 2021, EEC proposed to allocate an amount of $1.436 million to the RRO for shared service costs, an increase of approximately $180,000 over the approved 2020 costs.

The AUC found that EEC's request for $1.436 million was not reasonably supported. The AUC approved the continuation of the previously approved shared services amount of $1.256 million. This is a reduction of approximately $180,000 to the applied-for forecast costs for shared services, and this reduction includes the disallowance of $60,000 allocated to the centralization of safety, environment, and support services.

Restructuring of ENMAX Corporation

As of January 1, 2021, the task to support the RRO was moved from EPC to EEC. EEC provides the RRO service to customers and provides non-regulated or competitive electricity services. EEC noted that the manner in which the management and financial services costs were determined had not changed, and there is no material impact on its proposed revenue requirement. The difference between the $502,000 forecast and the $462,000 that would have been allocated to the RRO business unit by EPC was due to a change in the level of staff members performing the tasks.

The AUC approved $462,000 for management and financial services, as proposed by the Consumers Coalition of Alberta ("CCA") and the UCA. This amount would have been allocated applying the previously approved common costs allocation model. The AUC approved RRO operational costs in the amount of $1.537 million.

Salary and Non-Labour Escalation Factors

(a) Non-Labour Escalation Factor

EEC proposed to escalate its non-labour costs by 1.9 per cent. It noted the total cost increase is $0.1 million for 2021. The AUC approved the non-labour escalator proposed by the UCA. The UCA proposed to use the 2021 1.8 per cent Alberta consumer price index ("CPI") forecast that includes information from the Fall of 2020. This was the most recently available outlook at the time EEC filed its application.

(b) Salary Escalation Factor

EEC's 2021 forecast increase for the cost of labour is 2.0 per cent and 3.0 per cent for bargaining unit employees ("CUPE") and management and professional ("MP") salary increases, respectively. EEC's 2.0 per cent bargaining unit forecast increase for 2021 is based on information from ATCO Electric, ATCO Power, and Capital Power.

The UCA proposed to use for 2021 the forecast Alberta average wage rate increase for all industries from the Calgary and Region Economic Outlook 2020-2025 (Fall 2020), which is the most recent outlook and a better proxy for the current economic conditions. The AUC accepted this evidence and directed EEC to update its bargaining unit salary increase from 2.0 per cent to 0.0 per cent, as part of EEC's application for disposition of the COVID-19 deferral account.

The AUC determined that EEC's position on a 3.0 per cent MP salary escalator for 2021 is discordant with actual salary information available, particularly because there has been a salary freeze by ENMAX Corporation in 2020. The AUC found a 0.0 per cent increase for 2021 MP staff to be reasonable.

Final Notice Fees, Late Payment Charges and Customer Resolution Fees

The AUC approved the inclusion of 2021 final notice fees and late payment charges in EEC's COVID-19 deferral account. It approved 1.8 per cent as the escalation factor for 2021 customer resolution costs, consistent with the non-salary escalation factor approved in this decision.

Final 2021 Non-Energy Rates and the Need for Compliance Filing to this Decision

EEC was directed to maintain final non-energy rates for 2021 at the level of EEC's 2020 final non-energy rates. Accordingly, the AUC approved final 2021 daily non-energy administration charges of $0.2201 per day for residential customers, and $0.1975 per day for small commercial customers, subject to adjustments necessary for disposition of the COVID-19 deferral account

***Shell Canada Limited Scotford Solar Power Plant and Industrial System Designation Amendment,* AUC Decision 26423-D01-2021**

Solar Power Plant - Facilities

In this decision, the AUC approved the applications from Shell Canada Limited ("Shell") to construct and operate a 4.6-megawatt ("MW") solar power plant at the Scotford industrial complex in the Fort Saskatchewan area and to amend the Scotford industrial system designation ("ISD") to include the power plant.

Is Approval of the Solar Power Plant in the Public Interest?

The proposed power plant would be located in the Alberta Industrial Heartland, where the Northeast Capital Industrial Association manages noise from energy-related facilities through its Regional Noise Management Plan. The AUC required that new facilities should result in no net increase above baseline case sound levels at nearby receptors. Based on the noise impact assessment submitted by Shell, the AUC concluded that the power plant is expected to comply with this noise requirement.

The solar glare assessment conducted by Solas Energy Consultants for Shell identified that Range Road 214 is expected to receive up to 4,956 minutes of yellow-grade glare per year. Shell submitted that Range Road 214 is a dirt road that is not heavily travelled. The AUC noted that there were no public safety standards or regulations associated with solar glare at the time of this proceeding that apply to the power plant. The AUC accepted the submitted assessment and did not consider adverse glare impact to be likely. The AUC noted its expectation that any glare issue caused by the power plant would be addressed in a timely manner. Accordingly, the AUC imposed the following conditions of approval:

(a) Shell shall apply anti-reflective coating to the project solar panels.

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

The AUC recognized that renewable energy operations must obtain a reclamation certificate at the power plant's end of life and expects Shell to comply with all applicable statutory reclamation obligations. The AUC found that adverse environmental impacts were unlikely.

The AUC determined that approval of the power plant is in the public interest regarding its social, economic, and other effects, including its effect on the environment.

Would the Scotford Industrial System Continue to Meet the Requirements for Designated Industrial Systems with the Inclusion of the Solar Power Plant?

The Scotford industrial complex has been designated as an industrial system since 1999. As a result, the AUC considered that the principles and criteria set out in Section 4 of the *Hydro and Electric Energy Act* ("*HEEA*") would have been assessed when the designation was initially applied for. As such, it was not necessary for the AUC to make findings on the applicability of principles and criteria to aspects of the industrial system that were originally considered in the initial ISD application and that are not materially altered by the proposed amendment.

AltaLink Management Ltd. ("AML") was concerned that the proposed solar power plant may not fit within the criteria for an ISD set out in Section 4 of the *HEEA.* However, the AUC found that AML did not have standing in this proceeding and placed little or no weight on the submissions of AML.

The AUC determined that the inclusion of the solar power plant into the industrial system constitutes a minor alteration to the industrial system. The solar power plant is expected to supply 0.4 per cent of the industrial complex's electricity requirements and would not alter the industrial system's status as a net-importer.

The AUC determined that the principles and criteria of Section 4 of the *HEEA* would continue to be met. Accordingly, the AUC found that approving the application to amend the Scotford ISD is in the public interest and that the industrial system, given the minor nature of the amendment, continues to meet the principles and criteria of Section 4 of the *HEEA*.

Decision

The AUC approved the power plant application under Section 11 of the *HEEA*. It further approved the ISD amendment application under Section 4 of the *HEEA* and sections 2(1)(d) and 117 of the *Electric Utilities Act*.

***WCSB Power Holdings GP Ltd. Application for an Order Permitting the Sharing of Records not Available to the Public,* AUC Decision 26507-D01-2021**

Market Oversight and Enforcement - FEOC

In this decision, the AUC approved the application by WCSB Power Holdings GP Ltd. ("WCSB") for the preferential sharing of records that are not available to the public between WCSB, WCSB Holdings Limited Partnership ("WCSB LP"), URICA Energy Real Time Ltd. ("URICA Real Time") and URICA Asset Optimization Ltd. ("URICA Optimization"), relating to the eReserve2 Battery Energy Storage Power Plant ("eReserve2"), which consists of 14 1.5-megawatt (MW) lithium-ion batteries, for a total generating capacity of 20 MW (the "Power Plant").

Submissions of the Applicant

Is the Proposed Sharing of Records Necessary?

WCSB identified that it had entered into commercial arrangements with URICA Real Time and URICA Optimization that necessitate that WCSB and WCSB LP share offer information with URICA Real Time and URICA Optimization that is not available to the public.

WCSB explained that neither it nor WCSB LP has the expertise and resources to accept energy or ancillary services dispatch orders to manage the Power Plant's output in the Alberta energy or ancillary services markets on a 24-hour basis. URICA Real Time has the expertise and resources to assist by providing the needed real/time dispatch desk service. URICA Optimization has the expertise and resources needed to assist WCSB with establishing and optimizing offer strategies for the Power Plant.

FEOC Operation of the Electricity Market

WCSB filed written representation indicating that the records subject to preferential information sharing will not be used for any purpose that does not support the fair, efficient, and openly competitive operation of the Alberta electricity market, including but not limited to the conduct referred to in Section 2 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

Offer Control

WCSB submitted that WCSB and WCSB LP's total offer control is 0.6 per cent, that URICA Real Time's total offer control is zero per cent, and that URICA Optimization's total offer control is 1.0 per cent, all of which are less than the offer control limit of 30 per cent, as set out in Subsection 5(5) *FEOC Regulation*.

AUC Findings

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

The AUC was satisfied that WCSB had demonstrated that the sharing of records is reasonably necessary for WCSB to carry out its business. It was further satisfied that the subject records would not be used contrary to the fair, efficient, and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation* and that the applicants would conduct themselves in a manner that would support the fair, efficient and openly competitive operation of the market. The AUC also found that the offer control limit of the entities was less than 30 per cent, as required by Subsection 5(5) of *FEOC Regulation*. The AUC noted that the Market Surveillance Administrator supported the application. The AUC was prepared to issue the order approving the applied-for sharing of records, subject to terms and conditions set out in the decision.

CANADA ENERGY REGULATOR

Hydro-Québec TransÉnergie Application to Construct an Interconnection Power Line Appalaches-Maine Interconnection Power Line Project, CER Letter Decision A7T7Y8

Facilities - Electricity

In this decision, the CER issued electricity Permit EP-305 (the "Permit") to Hydro-Québec TransÉnergie ("HQT"). The Permit allows HQT to construct and operate a 103 kilometer ("km") long +/- 320 kilovolt ("kV") direct current ("DC") power line between Appalaches substation in the municipality of Saint-Adrien-d'Irlande and a crossing point on the Canada-United States border in the municipality of Frontenac (the "Project").

Project Overview and CER Process

The Project involves the construction of approximately 100.8 km of +/- 320 kV DC power line between the Appalaches substation in the municipality of Saint-Adrien-d'Irlande, Québec, and the New England Clean Energy Connect ("NECEC") transmission line in the State of Maine. The Project will leave Canada at a border crossing point in the municipality of Frontenac, Québec. The proposed international power line ("IPL") will enable HQT to provide New England with up to 1,200 megawatts ("MW") of power at +/- 320 kV DC. The overall cost of the project is estimated at $603 million.

Comments Related to Upstream Facilities

The Pessamit Innu First Nation, Wemotaci Atikamekw First Nation, and the Pikogan, Lake Simon, and Kitcisakik Anishnabeg First Nation (the "Coalition of First Nations") and the Innu Nation of Labrador ("Innu Nation") submitted letters of comment. They raised issues regarding a lack of consultation related to the operation and maintenance of upstream facilities, particularly the Churchill Falls Hydroelectric Complex ("CFHC"). The Coalition of First Nations and the Innu Nation argued that the Crown's duty to consult was not upheld and that they had been deprived of constitutional rights.

Views of the CER

The CER noted and considered arguments and concerns raised by both the Coalition of First Nations and the Innu Nation. The CER found that, while they each raised different arguments, they both related to the upstream generating facilities. This application under consideration concerned the construction and operation of a transmission line, which will use existing facilities operating within approved parameters. The CER, in reviewing the application, was not faced with the issue of new generating facilities.

The CER considered whether the effects of the upstream generating facilities should be included in the assessment as being incidental to the Project. The CER considered criteria provided by the Impact Assessment Agency to assist in deciding whether it should include the incidental activities in the scope of its assessment. The CER determined that the issues related to upstream facilities raised by the Coalition of First Nations and the Innu Nation were not properly within the scope of this proceeding.

The Innu Nation, referring to the UN Declaration, argued that the Project could not be found to be in the public interest if past and ongoing impacts of the CFHC remained unaddressed. Until such issues had been addressed, the Innu Nation argued that a new way to derive profits from the CFHC should not be allowed. The CER was of the view that an increase in profits, which would come from electricity generated on the entirety of the Hydro-Québec system, is not an adverse effect on the rights of the Innu Nation. The CER found that the applied-for permit does not cause a breach of the Innu Nation's protected rights.

The CER further denied the request from the Innu Nation to impose a condition that would require HQT to obtain permission from the Innu Nation to use Innu Territory for the CFHC. The CER denied the requested condition for the Project because the CFHC is not directly related to the Project. The CER repeated that the CFHC is an upstream facility that is regulated provincially, which has no new impacts directly related to the Project.

Facilities Safety and Emergency Management Matters

Based on the information provided by HQT in its application and responses to information requests, the CER was satisfied by the overall design and determined that the Project, as proposed, would meet the applicable engineering requirements. Further, the CER was satisfied that the Project would comply with all applicable safety standards and reliability standards, and no issues were raised. The CER imposed conditions to ensure that commitments to abide by these standards were followed in the construction and operation.

HQT stated that the import limit capabilities of the IPL had not yet been confirmed. The CER imposed Condition 16 requiring HQT to confirm transfer capabilities limits.

The CER found that HQT's commitment to adhere to applicable safety standards, combined with emergency prevention, preparedness, and response practices described in the application, corresponds to the CER's Emergency Management expectations.

Economic Feasibility

Need for Facilities

HQT stated that the project serves to increase its capacity to export electricity to the major markets in Massachusetts and Maine. The Project will increase profitable exports for HQT, which, as a government corporation, pays a large dividend to the Province of Québec.

In March 2018, the NECEC project proposal submitted by Exploitation et Hydro-Québec Production ("EHQP") in partnership with Central Maine Power was selected by the Massachusetts electricity distributors.

HQT stated that the existing interconnection points with New England do not have the capacity to receive an additional transmission reservation of 1200 megawatts. HQT stated that the power purchase and transmission agreements with the Massachusetts distributors and Central Maine Power, which stipulate annual delivery of 9.45 TWh of energy for 20 years, show an adequate market for the power line proposed in this request.

Despite concerns raised by participants regarding an adequate financial or business plan of HQT, the CER was satisfied with the information presented by HQT, demonstrating that the Project is responding to market need and that the Project would increase the export capacity of Québec.

Ability to Finance Construction and Operation

The CER determined that HQT had demonstrated that it had sufficient financial resources in place to finance the construction and operation of the Project. HQT estimated the service life of the proposed IPL at around 80 years. The CER was also satisfied that HQT was in a financial position to finance the future abandonment of the project.

Land Matters

The CER was satisfied that the significant effort made by HQT, including the route selection criteria and the modified route, took stakeholder concerns into account and minimized potential environmental and social impacts. The CER found that the route selection criteria used was appropriate as it follows existing infrastructure as much as possible, such that over 73% of the route follows the existing right-of-way ("ROW") and therefore reduces environmental and social impacts. The CER further noted that over 99% of the Project is located on private land. As detailed route and land acquisition with respect to the Project will be carried out under provincial laws, the CER acknowledged that the Province of Québec would consider these matters.

Environment and Socio-Economic Matters

Comments from interested parties made submissions to the CER regarding environmental and socio-economic matters raised issues concerning impacts on wildlife and wildlife habitats, watercourses, wetlands, vegetation, climate change, health, traditional land use ("TLU"), and heritage resources.

The CER noted the responsibility of the Government of Québec to oversee the Project as part of the province's issuance of the certificate under provincial jurisdiction. The Bureau d'audiences publiques sur l'environnement ("BAPE") provided recommendations to the province to impose conditions on its approval of the Project to protect the biophysical and human environment. These recommendations included mitigation and/or compensation measures related to issues that were raised through the CER public comment period. The CER was satisfied that HQT identified and addressed environmental and socio-economic effects associated with the Project, including those raised through the public comment process.

The CER imposed Condition 9 requiring HQT to submit an Environmental Protection Plan ("EPP") prior to beginning construction. As part of the EPP, to ensure HQT's acts according to its commitment to inform impacted peoples in the event of a heritage resource discovery, the CER required a Heritage Resource Discovery Contingency Plan. The CER also imposed conditions requiring that HQT file a Finalized Watercourse Crossing Inventory and post-construction monitoring reports.

Given the nature and scope of the Project as applied for, the mitigation measures proposed by HQT, the fact that 99% of the ROW is on private lands, and that the IPL will parallel disturbances for 73% of the route, as well as recommendations in the BAPE Report and the CER's mitigating conditions, the CER found that the Project is not likely to cause significant environmental or socio-economic effects.

Matters Related to Indigenous Peoples

HQT stated that the Project is subject to a provincial environmental impact assessment and review procedure by the Ministry of Sustainable Development, Environment, and Fight Against Climate Change ("MELCC"), which is also responsible for the process of Indigenous consultation by the Provincial Crown. At the time of submitting its Application in September 2020, the process of Indigenous consultation by the Provincial Crown was ongoing.

HQT focused the bulk of its engagement efforts with the Grand Conseil de la Nation Waban-Aki ("GCNWA") in developing its applied-for route. HQT stated that the applied-for line route would not affect the area designated for hunting, trapping, and communal fishing activities.

The CER notified Indigenous communities potentially affected by the Project and encouraged the communities to contact HQT with their concerns and to participate in the BAPE review proceeding.

The GCNWA raised concerns regarding the Project's impact on cultural and heritage resources; and cumulative impacts on their Ndakina traditional territory, affecting their preservation and continuation of the Waban-Aki culture. The Huron-Wendat Nation ("HWN") submitted that they had received no real consultation from HQT and requested that before issuing a permit to HQT, the CER provide the nation with adequate funding so they may determine the potential effects on their ancestral rights and treaty issues; consult the nation on these effects and prescribe accommodations; and prepare a plan, in collaboration with the nation, for mitigating impacts.

The CER found that there had been adequate consultation and accommodation for the purpose of the CER's decision on the Project. The CER also found that any potential project-related impacts on the interests, including rights, of affected Indigenous peoples are not likely to have an adverse effect and can be effectively addressed. As a result, the CER found that the issuance of a permit under section 248 of the *CER Act* is consistent with section 35 of the *Constitution Act* and the honour of the Crown.

Conclusion

The CER issued Permit EP-305, giving effect to this decision.

Trans Mountain Pipeline ULC Request for Confidential Treatment, Amended Order AO-001-FRO-002-2017

Confidentiality

In this decision, the CER granted the request from Trans Mountain ULC ("Trans Mountain") to file in confidence information in its certificate of insurance that discloses the names of its insurers.

All pipeline companies regulated by the CER must file financial resources plans each year showing that that company has enough resources to cover the company's expected liabilities if a pipeline spills. Trans Mountain requested an exception to the typical public filing process, asking the CER to keep their insurers confidential going forward. On April 29, 2021, the CER granted the request by making an order under section 60 of the *Canadian Energy Regulator Act* ("*CER Act*") to keep the identity of Trans Mountain's insurers confidential. The decision pertains only to the insurance in place to cover liability for operating the Trans Mountain pipeline.

Requirements to be Met

The confidential treatment of the information in question requires that Trans Mountain meets the requirements set out in Subsection 60(a) and 60(b) of the *CER Act.*

> The CER or a designated officer may take any measures and make any order that the CER or designated officer considers necessary to ensure the confidentiality of any information likely to be disclosed in any proceedings under this Act if the CER or designated officer is satisfied that
>
> (a) disclosure of the information could reasonably be expected to result in a material loss or gain to a person directly affected by the proceedings, or could reasonably be expected to prejudice the person's competitive position;
>
> (b) the information is financial, commercial, scientific or technical information that is confidential information provided to the Regulator and
>
> > (i) the information has been consistently treated as confidential information by a person directly affected by the proceedings, and
> >
> > (ii) the Commission or designated officer considers that the person's interest in confidentiality outweighs the public interest in disclosure of the proceedings; or
>
> (c) there is a real and substantial risk that disclosure of the information will compromise the safety and well-being of persons or cause harm to property or the environment.

Section 60 sets out how the CER must approach granting a limited exception to the fundamental principle that its proceedings need to be open, accessible, and transparent. The CER has held that the granting of an order under section 60 is an extraordinary order, and the onus to meet the test to set aside and open public process is on the company requesting it.

Trans Mountain's Request

Trans Mountain provided evidence that disclosing the names of its previous insurers in prior such filings had previously resulted in the termination of insurance coverage. While Trans Mountain replaced this coverage, it experienced a significant reduction in available insurance capacity and incurred a significantly higher cost. Trans Mountain submitted that if there is continued public disclosure of the names of its insurers, there will be ongoing targeting and pressure placed on insurers which could be expected to have the same result. Trans Mountain stated this would result in a material loss to it and its shippers because of increased insurance premiums. The increased premiums would result from a smaller pool of insurers and challenges maintaining adequate insurance coverage, as required by section 138 of the *CER Act*. Loss to Trans Mountain and its shippers in the form of (i) higher insurance; and (ii) challenges in maintaining adequate insurance coverage to fulfill its significant financial resource obligations under section 138 of the CER Act.

In support of its request, Trans Mountain referred to a previous decision regarding Genesis Pipeline Canada Ltd. and NOVA Chemicals (Canada) Ltd. where confidentiality over the names of the insurers was granted pursuant to the predecessor to Subsection 60(b) of the *CER Act*. Trans Mountain argued that consistent with this precedent, its interest in confidentiality outweighed the public interest in disclosing the insurers' names.

Comments Received About the Request

Comments submitted to the CER raised concerns arguing that granting confidentiality would deprive Canadians of their right to know that sufficient insurance is available to cover catastrophic events and provide necessary compensation. Further comments included un-insuring of fossil fuel projects, such as the Trans Mountain Pipeline, as the best non-violent way of shifting Canada towards a carbon-free energy future. They further argued that the confidential treatment would hinder the protection of Indigenous rights. Further, they argued that the increase in insurance costs and decreased coverage feared by Trans Mountain is not a result of public pressure. Instead, they are the result of a trend in the insurance industry of considering the cost of climate change and divesting away from fossil fuel projects, as well as Trans Mountain’s safety record.

Trans Mountain responded to comments and concerns raised about the project by noting that the rising costs in the insurance industry are not supported by evidence and are irrelevant to the test for confidentiality.

Decision

The CER noted that the confidentiality request is in relation to very little information. Only the names of the insurers would be removed, while the public record would still show information about Trans Mountain's insurance, including the limit of liability/amount of coverage attributable to each un-named insurer.

The CER agreed that Canadians should have the opportunity to make themselves aware via publicly filed information that sufficient financial resources are available and are maintained to cover catastrophic events. However, the CER found that this opportunity is provided through the requirements of the *CER Act*, the *Pipelines Financial Requirements Regulations*, and the CER's assessment of companies' financial resources plans. It is the responsibility of the CER to assess whether the financial resources requirements are met.

In response to comments stating that un-insuring fossil fuel projects, such as the Trans Mountain Pipeline, is the best and non-violent way of shifting Canada towards a carbon-free energy future, the CER noted that determining the nature and composition of Canada's energy future may be a worthy policy debate. However, the CER could not ignore the statutory requirement that the pipelines and facilities regulated by the CER carry appropriate insurance or similar financial resources. Further, this requirement serves a vital public interest.

The CER determined Trans Mountain had met the requirements for confidentiality under both subsections 60(a) and 60(b). For 60(a), the CER found "the disclosure of the names of Trans Mountain's insurers could reasonably be expected to prejudice its competitive position in its dealing with potential insurers", and for 60(b)(ii) found that Trans Mountain's interest in confidentiality outweighs the public interest in disclosure of the names of Trans Mountain's insurers, and that there was a public interest in knowing the pipeline is sufficiently insured, but not in the particulars of all insurers.

The CER granted the relief requested by Trans Mountain to file in confidence information its certificate of insurance that discloses the names of its insurers.

The CER determined that this confidential treatment may be applied to all future filings of the names of the insurers, as set out in Trans Mountain's certificate(s) of insurance unless there is a material change.