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.

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ALBERTA UTILITIES COMMISSION

ENMAX Power Corporation 2019 Distribution Tariff Phase II Application, AUC Decision 24820-D01-2020

Rate Design - Terms and Conditions

In this decision, the AUC addressed the 2019 Distribution Tariff Phase II application filed by ENMAX Power Corporation ("ENMAX"). For the reasons set out in this decision, the AUC approved:

- The cost allocation study, with the exception of the methodology of classification and allocation of primary tap ("Primary Tap") costs, and the assumptions and use of physical asset data, as filed;
- The methodology and allocation of transmission system access service as filed;
- The requested rebalancing of all rate class distribution access service ("DAS") revenue-to-cost ratios as filed; and
- The proposed rate design and fixture forecasting methodology as applied for.

The AUC denied ENMAX's proposed increase of the fixed percentage of its DAS rate for the residential (D100) and small commercial (D200) rate classes.

Overview of ENMAX's Application

ENMAX requested approval of its proposed distribution and transmission tariffs and terms and conditions of service ("T&Cs"), supported by a full cost-of-service study ("COSS") and corresponding rate design.

Statements of intent to participate were received from the Office of the Utilities Consumer Advocate, the Consumers' Coalition of Alberta, AltaLink Management Ltd., the Canadian West Ski Areas Association (CWSAA), the Canadian Solar Industries Association, and Matthew Jones (representing Macdonald Communities Limited ("MCL").

Cost Allocation Study

The submitted cost allocation study included the steps of functionalization, classification and allocation, and attributed ENMAX's total revenue requirement to each of its rate classes. The submitted cost allocation study used the same methodology approved by the AUC in Decision 2010-151. ENMAX noted there were two exceptions to this:

- Accounting methodology: ENMAX adopted the AUC's Uniform System of Accounts and modified its accounting systems in 2010; and
- Classification of Primary Taps: ENMAX previously classified Primary Taps as a combination of fixed and variable costs. In this application, ENMAX classified Primary Tap costs as 100 percent fixed costs, also referred to as site- or customer-related costs.

The cost allocation study classified approximately two-thirds of the distribution revenue requirement as site related and one-third as demand related.

Findings

The AUC approved the cost allocation study as filed, with certain exceptions.

(a) Classification of Primary Tap costs

ENMAX proposed to change the classification of Primary Tap costs from the ratio approved in its 2008-2016 Phase II application to 100 percent site related costs. To classify Primary Tap costs, ENMAX considered how the overall project cost may change if the peak demand increased. It concluded that it would not. Primary Tap stays relatively constant for a wide range of transformer capacities. Primary Tap costs were classified as 100 percent site related.

To allocate Primary Tap costs, ENMAX developed typical tap costs for residential, commercial and single-phase overhead taps, as well as for single-phase and three-phase underground taps. The cost of this configuration was then divided by 20 to determine the Primary Tap cost for each single-phase overhead transformer. ENMAX used these estimates to allocate Primary Tap costs based on the number of transformers of each type and size allocated to each rate class.

The AUC noted that in ENMAX's 2008-2016 Phase II application, ENMAX classified and allocated Primary Tap costs using a methodology similar to the one in this application; however, it determined in that cost allocation study that a portion of the costs for three-phase underground taps varied with the size of the associated transformer. This resulted in some Primary Tap costs being classified as demand related.

The AUC found it unclear how the cost allocation study concluded that first attributing cost to rate classes would lead to the demand component of classification no longer being a factor. The AUC was concerned that the analysis ENMAX completed provide the necessary information needed to properly classify Primary Tap costs and assess whether there are correlations between Primary Tap costs and customer demand.

The AUC approved the classification of Primary Tap costs as 100 percent site related as it was a small change from the previous ratio and was determined based on an updated analysis that was used to determine the previous ratio. The AUC directed ENMAX to complete an analysis that includes consideration of Primary Tap costs on a per customer basis in its next Phase II application.

Assumption and the Use of Physical Asset Data

ENMAX was directed to provide an analysis of whether the calculation of any of its allocators would result in increased utilization of actual asset and electrical connectivity data from its databases. ENMAX was directed to adopt all updated allocation methods that are found through this analysis to provide more accurate allocations in a cost-effective manner in its next Phase II application.

System Access Service

ENMAX is charged for system access service ("SAS") by the AESO in accordance with the AESO DTS rate. ENMAX flows through these SAS charges to its customers in its distribution tariff. The AUC approved ENMAX's methodology and allocation of transmission SAS costs, as filed.

<u>Rate Design</u>

Distribution Access Service Rates

(a) Revenue to Cost Ratios

The AUC found ENMAX's recommendation to rebalance all rate class DAS revenue-to-cost ratios to 100 percent to be reasonable and approved ENMAX's request as applied for.

(b) Residential (D100) and Small Commercial (D200) Rate Classes

The AUC denied ENMAX's proposal to increase the fixed percentage of its DAS rate for the residential (D100) and small commercial (D200) rate classes to 87 percent and 88 percent, respectively. The AUC was not persuaded that ENMAX's applied-for rate design change for D100 and D200 rates is just and reasonable. The AUC directed ENMAX in its compliance filing to recalculate its rate design for these two rate classes to maintain the current weighting between fixed and volumetric rates in its DAS rates, namely 74 percent and 76 percent site charges for D100 and D200, respectively.

(c) Medium Commercial (D300) and Large Commercial (D310 and D410) Rate Classes

The AUC found ENMAX's proposal to adjust the rates for these rate classes, so that the fixed charge component recovers 100 percent of customer-related fixed costs and the demand charge recovers 100 percent of the demand-related costs, to reflect the cost causation rate design principle and as such is generally reasonable, subject to some reservations set out in this decision. In the interest of reflecting the important principle of setting effective price signals, the AUC directed ENMAX in its compliance filing to adjust the rate design to maintain the portion of the total DAS rates that are able to vary between billing periods.

(d) Streetlights D500

The AUC approved the proposed rate design and fixture forecasting methodology as applied for as it found the total fixture count forecast methodology to be logical and consistent with previously approved methodologies in analogous situations.

System Access Service Rates

The CWSAA raised concerns with the irregularity of updates to ENMAX's System Access Service ("SAS") rates. The CWSAA noted that because ENMAX had not updated its SAS rates since 2011, ENMAX's deferral account adjustments had grown to comprise a significant component of customers' SAS rates. The AUC shared the CWSAA's concern about the lack of regularity in updates to ENMAX's SAS rates. The AUC directed ENMAX to update its SAS rates to the 2020 DTS rates, and incorporate an updated pool price forecast in its compliance filing.

Rate Classes

In the context of the D100 and D200 rate classes the AUC accepted ENMAX's proposal to retain its existing rate classes for the purposes of this application. ENMAX was directed to undertake a study to determine, based on homogeneity and any other relevant factors, if a further subdivision or stratification of the D100 and/or D200 rate classes is warranted. ENMAX was also directed to examine organizing rate classes using currently installed metering infrastructure, as well as if an AMI system was fully deployed.

Terms and Conditions for Electric Distribution Service

Concerns Raised by MCL

MCL stressed the absence of transparency in ENMAX's cost estimate quotes for an infrastructure installation and noted ambiguity surrounding ENMAX's contractor selection process to fulfill the installation of a facility.

The AUC directed ENMAX to outline specifics of the calculations of ENMAX's investments for standard and non-standard residential developments in its compliance filing to this decision and, subject to AUC approval, incorporate this information into appendixes as part of the T&Cs.

The AUC directed ENMAX to propose an approach, in the compliance filing, to provide information to customers related to the contractor selection process. The AUC further directed ENMAX to provide an option for developers to contract themselves for facilities.

The AUC considered that greater transparency is owed to customers when a portion of the costs of installing new infrastructure is ultimately paid by them. Accordingly, the AUC directed ENMAX in its compliance filing to propose a method of providing greater transparency in relation to contractor costs in the bidding process.

Customer and Retailer Terms and Conditions

As part of its application, ENMAX sought approval of certain revisions to the T&Cs of its service. ENMAX informed the AUC that to improve clarity, consistency and transparency of such documentation, it had redrafted and reorganized the terms and conditions.

The AUC noted that the majority of its concerns pertaining to the customer and retailer T&Cs had been addressed. Accordingly, the AUC directed ENMAX to update its customer terms and conditions, and retailer terms and conditions, as provided in this decision and in Appendix 2 to this decision, as part of its compliance filing.

***Alberta Electrical Systems Operator 2019 Deferral Account Reconciliation Interim Settlement,* AUC Decision 25768-D01-2020**
Interim Refundable Approval - Settlement of Net Deferral Account Shortfall

In this decision, the AUC approved, on an interim and refundable basis, the Alberta Electric System Operator's ("AESO") request to settle its 2019 net deferral account shortfall with market participants, in the amount of $41.6 million.

On July 31, 2020, the AESO filed an application requesting approval of its 2019 deferral account reconciliation and for changes to deferral account balances from 2012 through 2019. The AESO requested approval of the determination and allocation of a $41.6 million net deferral account shortfall and approval to collect and refund the allocated amounts.

Findings

The schedule established for IRs did not permit the AUC to issue a final decision, prior to the requested deadline for an interim decision of September 3. 2020. The AUC planned to issue information requests ("IR"s) to the AESO before making a decision on a final basis. The AUC recognized that approval of the application, on an interim refundable basis, would enable the AESO to settle its outstanding net deferral account shortfall on invoices issued in September 2020.

The AUC agreed with the AESO's statements that interim approval would result in rate stability, intergenerational equity and will minimize accrued interest. For these reasons, the AUC found that the AESO's request to settle its 2019 net deferral account shortfall with market participants, in the amount of $41.6 million, on an interim and refundable basis, was in the public interest and was therefore approved.

***EPCOR Water Services Inc. - E.L. Smith Battery Energy Storage System,* AUC Decision 25770-D01-2020**
Alteration of E.L Smith Solar Power Plant - Increasing Operational Performance

In this decision, the AUC approved the application from EPCOR Water Services Inc. ("EPCOR Water") for the alteration of a power plant designated as the E.L Smith Solar Power Plant.

Background

EPCOR Water filed a letter of enquiry, pursuant to Sections 11 and 12 of *the Hydro and Electric Energy Regulation ("HEEA")*, for minor alterations to the approved but not yet constructed 12-megawatt (MW) power plant designated as the E.L. Smith Solar Power Plant. The application was registered on July 31, 2020, as Application 25770-A001.

Discussion

EPCOR Water proposed to add a 4-MW/8.9-megawatt-hour (MWh) battery energy storage system to the E.L. Smith Solar Power Plant. This would increase the operational performance of the power plant by balancing supply and demand of electricity and serving as a backup power supply for the E.L. Smith Water Treatment Plant.

An environmental evaluation assessing the incremental impacts of the battery energy storage system predicted no significant effects to the environment.

Findings

The AUC was satisfied that the proposed minor alteration would not adversely and directly affect any person and no significant adverse environmental impact would be caused. Based on the information provided by EPCOR Water in accordance with Section 12 of the *Hydro and Electric Energy Regulation*, and its findings, the AUC approved the application pursuant to Section 11 of the *HEEA.*

***TERIC Power Ltd. eReserve2 Battery Energy Storage Power Plant Project,* AUC Decision 25691-D01-2020**

Stand-Alone Battery Energy Storage Facility - Power Plant

In this decision, the AUC approved the application from TERIC Power Ltd. ("TERIC") to construct and operate the eReserve2 Battery Energy Storage Power Plant Project, and to interconnect the facility to FortisAlberta Inc.'s ("FortisAlberta") distribution system.

Background

TERIC applied for approval to construct, operate and interconnect a 20-megawatt ("MW") battery energy storage facility, designated as eReserve2 Battery Energy Storage Power Plant Project (the "Project"). TERIC sought approval of the Project as a power plant, pursuant to Section 11 of the *Hydro and Electric Energy Act* ("*HEEA*") and to connect it to FortisAlberta Inc.'s 25-kilovolt distribution system pursuant to Section 18 of the *HEEA*.

The Project would consist of 14, 1.5-MW (approximately) lithium-ion battery modules with a total nameplate storage energy capacity of 20 MW-hours.

TERIC stated that it developed and conducted a participant involvement program in accordance with Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* and AUC Bulletin 2020-13: *Interim changes to AUC participation involvement program and related information requirement*.

TERIC stated, that it expected to use lithium-ion battery modular units such as Tesla Megapacks or Similar, although they had not formally selected an equipment supplier, make or model of the components.

TERIC stated that the Project is currently in Stage 1 of the AESO's connection process. It confirmed that the Project would participate in both the energy market and the ancillary services market. TERIC added that the AESO had not expressed any concerns with the interconnection proposal or the Project in general.

Findings

The proposed battery energy storage facility would not be associated with any other existing or proposed power plant and the battery modules would be charged from, and discharge energy to, the Alberta Interconnected Electric System ("AIES") through an existing feeder at FortisAlberta's Buffalo Creek 526S Substation.

The AUC considered the issue of whether a stand-alone battery energy storage facility is a power plant or generating unit as defined in the *Hydro and Electric Energy Act*. Similar to Decision 25205-D01-2020, the AUC was satisfied in this decision, that TERIC's proposed battery energy storage facility meets the definition of a power plant under *HEEA*

The AUC determined that the technical, siting, environmental and noise aspects of the proposed project met the Commission's Rule 007 and Rule 012 requirements.

The AUC found no outstanding public or industry concerns with the Project and found TERIC's participant involvement program to be adequate. Considering TERIC's commitment to follow all mitigation measures recommended in the environmental assessment report, and all applicable standards and guidelines, the AUC was satisfied that the Project would have minimal impacts on the environment.

TERIC planned to start construction in April 2021 and expected the in-service date to be in the early third quarter of 2021.

The AUC approved the Project as a power plant pursuant to Section 11 of the *HEEA.* The AUC approved the connection of the project to FortisAlberta's 25-kilovolt distribution system pursuant to Section 18 of the *HEEA*.

***Osum Production Corp. Orion Organic Rankine Cycle Power Plant, Industrial System Designation and Interconnection,* AUC Decision 25517-D01-2020**

Conditional Power Plant Approval - Industrial System Designation - Interconnection Application

In this decision, the AUC approved the application from Osum Production Corp. ("Osum") to construct and operate a power plant designated as the Orion Organic Rankine Cycle Power Plant, for an order to connect the power plant to ATCO Electric Ltd.'s 25-kilovolt distribution system, and for an industrial system designation ("ISD") for the Orion Commercial Plant (collectively, "the Project"). Osum also requested an ISD encompassing all the proposed facilities at the Orion Plant, including the proposed plant and distribution facilities and equipment.

Background

The proposed power plant would consist of one Organic Rankine Cycle turbine with a nameplate capacity of 19.4 MW. Osum stated that seasonal weather, ambient temperature and operational conditions would affect the output of the proposed power plant, resulting in an anticipated output range between 9.5 MW and 16 MW.

The Project would be located within the boundary of the existing Orion Plant. The proposed power plant would be a closed-loop system. Osum submitted that the only adverse environmental impacts from the proposed power plant could be from contingency conditions, such as a fluid leak that would be contained within the Orion Plant.

The power plant was not predicted to result in significant environmental impacts, and an *Environmental Protection and Enhancement Act* amendment application would not be required. A completed noise impact assessment determined that the combined sound levels of the proposed power plant and existing Orion Plant facilities would exceed the nighttime permissible sound level at one receptor. Noise mitigation would therefore be required for the Project to comply with Rule 012: *Noise Control*. Noise mitigation measures such as a building or sound absorbing wall was proposed. It was concluded that, with the noise mitigation measures, the Project would meet permissible sound levels at all receptors.

The ISD proposed would encompass the facilities within the Orion Plant, including the proposed power plant and distribution facilities and equipment operating at 25 kV or less within the contagious area of the Orion Plant.

Osum provided an economic analysis of the Project that compared the proposed industrial system to the Orion Plant receiving all electric energy from the Alberta Interconnected Electric System ("AIES"). The analysis concluded that the cost of electricity for the project would be approximately $62.34/megawatt hour, while the cost of receiving electricity from the AIES would be $84.27/megawatt hour.

Osum planned for the Project to be in service within the first quarter of 2022.

Findings

The AUC determined that the technical, siting, emissions, environmental and noise aspects of the power plant meet the AUC's requirements, provided that the recommended noise mitigation is implemented.

The AUC found that the Project would meet the permissible sound levels stipulated in Rule 012 if the noise mitigation identified in the noise impact assessment is implemented. As such, the AUC's approval was conditional upon Osum's implementation of noise mitigation to ensure compliance with Rule 012.

The AUC was satisfied that the approval of the Project is consistent with the applicable principles set out in Section 4 of the *Hydro and Electric Energy Act ("HEEA")*, that the ISD will support an efficient exchange of electricity within the interconnected electric system and that the application meets all the requirements for an ISD.

The AUC approved the power plant application and the interconnection application pursuant to Sections 11 and 18 respectively of the *HEEA*. The ISD application was approved pursuant to Section 4 of the *HEEA* and Sections 2(1)(d) and 117 of the *Electric Utilities Act.*

Akamihk Energy Incorporated Montana First Nation Solar Facility Community Generation Application, AUC Decision 25657-D01-2020

Small Scale Generation Regulation - Conditional Approval

In this decision, the AUC qualified the Montana First Nation Solar Facility (the "Project") as a community generating unit pursuant to Section 3 of the *Small Scale Generation Regulation.*

Background

Akamihk Energy Incorporated ("Akamihk") was granted approval to construct and operate a 4.6-megawatt power plant designated as the Montana First Nation Solar Facility, located on land in the Montana Indian Reserve, No. 139.

On June 12, 2020, Akamihk filed Application 25657-A001 with the AUC for approval to qualify the Project as a community generating unit.

The AUC considered that the decision of this application would not directly and adversely affect the rights of a person pursuant to Section 9 of the *Alberta Utilities Commission Act*. Therefore, a notice of application was not issued, and a hearing was not required.

Discussion

In the application, Akamihk stated that it is wholly owned by Montana First Nation and that Montana First Nation meets the definition of community group under Subsection 1(e)(iv) of the *Small Scale Generation Regulation.*

FortisAlberta Inc. ("Fortis") confirmed that it had qualified the project as a small-scale generating unit under the *Small Scale Generation Regulation*. Fortis stated that it would be responsible for the metering costs of the Project should the AUC approve the community generating unit application.

Akamihk provided an estimate of $42,460.33 for materials and $8,122.46 for labour as the amounts that would be incurred for the Project meter.

The Project's construction start date was April 20, 2020, and its in-service date was estimated to be October 30, 2020.

Findings

As required by Section 3 of the *Small Scale Generation Regulation* Akamihk filed its application in the form established by the AUC and included a community benefits agreement between it and Montana First Nation as required.

The AUC found that Akamihk's application to designate the Project as a community generating unit satisfied the requirements of the *Small Scale Generation Regulation*.

The AUC qualified the Project as a community generating unit under *the Small Scale Generation Regulation*.

The AUC noted that the amount of $50,582.79 provided by Akamihk as the cost to be incurred for the Project meter includes installation fees, which are not eligible for compensation under Subsection 5(2)(a) of the *Small Scale Generation Regulation*. After subtracting the costs to install the metering system, the AUC determined that an accurate estimate for the cost to purchase the meter was $42,460.33.

The AUC was satisfied that as the distribution owner, Fortis was entitled to recover the cost incurred to purchase the meter for the Project from the Alberta Electric System Operator, pursuant to Subsection 5(3)(a)(i) of the *Small Scale Generation Regulation*. Under Subsection 3(3)(b) of the *Small Scale Generation Regulation*, the AUC determined that Fortis shall be compensated $42,460.33 for the cost to purchase the meter.

Notwithstanding this determination, the AUC required Akamihk to provide written confirmation of the actual meter cost once this amount is known no later than 30 days after the power plant is in service.

***ATCO Electric Ltd. 2018-2019 General Tariff Application Compliance Filing*, AUC Decision 24805-D02-2020**
Compliance with Decisions 22742-D01-2019, 22742-D02-2019, 24805-D01-2020, 25139-D01-2020, and 25282-D01-2020

In this decision, the AUC considered the application of ATCO Electric Ltd ("AET") for its compliance with directions from Decision 22742-D01-2019 and Decision 22742-D02-2019 ("Compliance Application").

The AUC required AET to file a consolidated application before the AUC to approve AET's compliance with certain directions provided in (i) the above-noted decisions; and (ii) Decision 24805-D01-2020, Decision 25139-D01-2020, and Decision 25282-D01-2020.

In this decision, the AUC considered AET's 2018-2019 General Tariff Application ("GTA") in Decision 22742-D01-2019 and declined to approve certain parts of AET's 2018-2019 forecast revenue requirement.

Consolidated Filing

AET was directed to file an application, referred to in this decision as a "consolidated filing," to demonstrate its compliance with all applicable outstanding directions.

Discussion of Issues

Compliance With Directions Issued in Decisions 22742-D01-2019 and 22742-D02-2019 and Other Matters Raised by AET in Its Application

(a) Direction 1 - Full Time Equivalents

The AUC considered the contentious issues identified by interveners or other issues that required further analysis by the AUC in this compliance proceeding. Unless otherwise specified, the directions referred to in the sections below are from Decision 22742-D01-2019.

In response to the AUC Direction 1, AET explained how it made its adjustments to comply with Direction 1 and provided calculations to demonstrate how the labour, fringe, IT and variable pay program ("VPP") forecast dollars changed as a result of its adjustments to full time equivalent ("FTE").

Owing to incomplete information and other weaknesses or deficiencies in the FTE-related evidence AET filed in this proceeding, it was difficult for the AUC to compare AET's FTEs in the 2018-2019 test period to past years, and to track actual and forecast FTEs by individual position to compare historical and forecast test years. AET was not able to track with any confidence its own FTEs.

The AUC found that AET failed to comply with Direction 1 on two grounds:

(i) 2018 Actual FTE Dollar Adjustments

AET calculated an average labour dollar per FTE and applied it to the change in the number of FTEs, to calculate the total labour dollar amounts included in its 2018 revenue requirement. Absent a specific direction from the AUC in Decision 22742-D01-2019 for AET to use average dollar per FTE, the AUC considered that AET's adjustment of its labour costs to be non-compliant with Direction 1.

(ii) Using the Actual 2018 FTEs as the Opening 2019 FTE Complement

AET was directed to use the 2018 actual FTEs as the opening 2019 FTE complement. The AUC had concerns regarding the same adjustments having been made to each of AET's 2018 FTEs and its 2019 FTEs. The AUC was of the view, that its direction requiring AET to use 2018 actual FTEs should have resulted in a difference between the 2019 opening FTEs and the total 2019 FTEs included in schedules 5-5.2 and 25-5.2 of its minimum filing requirement ("MFR") schedules, since the foundation upon which the adjustments were based had itself changed.

Recognizing AET's system limitations in recording FTEs, the AUC was concerned that AET was unable to cross-reference 181 FTEs. The AUC was unable to confirm the number of capital and operating and maintenance ("O&M") FTEs that should be included in AET's revenue requirement for 2019. As a result, the AUC directed AET to use its actual number of 2019 FTEs for the 2019 test year in its consolidated filing. AET was directed to use its 2019 actual labour and fringe amounts to adjust its schedules to comply with this direction in its consolidated filing.

(b) Direction 5 – Severance

AET calculated its severance costs for 2018 to be $5.2 million, a reduction of $0.7 million from its applied-for amount in Proceeding 22742.

The AUC rejected AET's view that additional information and evidence provided on the topic of severance is directly related to the severance Direction in Decision 22742-D01-2019 and was provided in accordance with the AUC's own direction. In its consolidated filing, AET was directed to reflect the recovery of $2.7 million in severance costs in 2018 subject to the removal of severance costs that are: (a) related to time spent providing affiliate services between 2014 and 2018; and (b) included in the 2018 $2.7 million severance costs; and the inclusion of that portion of 2018 severance, for positions listed in Table 3 in this decision, based on the portion of years of service that each severed employee worked for AET between 2014 and 2018, less any time spent providing affiliate services during the same period.

(c) Direction 8 – Variable Pay Program

The AUC was satisfied with the method that AET used to set variable pay ("VPP") forecasts at 80 percent of the eligible employee payout amounts and finds that AET has complied with Direction 8. However, AET was directed to, in its consolidated filing, update its VPP amounts to reconcile these schedules with any changes made in response to Direction 1.

(d) Direction 9 – VPP Reserve Account

In compliance with Direction 9, AET offered a proposal for how its VPP reserve balance may operate as close to zero as possible and any changes to the structure or operations of the VPP reserve should only be made in a future GTA. With respect to the mechanics of AET's reserve account and the treatment of any accumulated balance in AET's VPP reserve balance, the AUC agreed with AET that this issue is best dealt with in AET's 2020-2022 GTA proceeding, Proceeding 24964. The AUC's direction remained outstanding and is to be addressed by AET in its next GTA.

(e) Direction 20 – Income Tax

Direction 20 required AET demonstrate in its compliance filing to Decision 22742-D01-2019, using information available on the record of that proceeding, that its treatment of allowance for funds used during construction

(“AFUDC”) in its calculation of income tax expense does not, as is described in paragraph 267 of Decision 22742-D01-2019 involve charging customers current tax expenses by adding AFUDC to the total utility earnings before tax; or removing AFUDC from its undepreciated capital cost pool and charging customers current tax expenses over the asset’s service life, as demonstrated by the difference in the current tax expense total.

The AUC determined that, because AFUDC was capitalized and recovered through future period revenue requirements, the addition of AFUDC to the “Utility earnings before tax” while the asset is under construction and not yet in service resulted in AFUDC being included twice. AET was therefore directed to adjust its AFUDC in the “utility earnings before tax” in Schedule 7-3 of its MFR schedules to comply with the AUC’s findings with respect to AFUDC in this decision.

(f) Direction 21 – Income Tax

The AUC did not accept AET’s current calculations and found that AET should not have added AFUDC to its “utility earnings before tax” when calculating its tax expense for purposes of determining its revenue requirement.

The AUC directed AET to include the refund/collection calculation for the differences in 2017 AFUDC tax inputs between the forecast and actual costs, as part of its settlement of deferral account balances in a compliance filing to Proceeding 24375 and to calculate carrying costs on the refund/collection for the 2017 AFUDC tax input, as approved in Proceeding 24375.

(g) Direction 32 – USA 934 – IT General and Administration Expense

In compliance with the direction regarding the 2019 FTEs, AET was directed to adjust its forecast expenses for this account based on the AUC’s reduction in forecast FTEs in its consolidated filing.

(h) Direction 37 – Allocation of Head Office Rent Costs - Rent Escalator

AET was proposing that the $1.00 per square foot per year escalation be approved. The CCA submitted that AET’s request was unsupported by the evidence provided and should be denied because AET provided a recommendation that was inconsistent with the evidence. The AUC denied the escalator of $1 per square foot in each of the 2018-2019 test years and directed AET to reflect any changes to its revenue requirement and supporting schedules in the consolidated filing.

(i) Direction 38 – Allocation of Head Office Rent Costs

AET was directed to compute the square footage in its allocation of corporate rent for ATCO Park on the basis of (260/600) x 21 percent. The numerator is the sum of head office employees and shared services employees identified in Undertaking 52, adjusted for the seven percent vacancy factor. The denominator of 600 is the total employee capacity of ATCO Park.

AET calculated that the head office square footage allocated to it was 14,105 sq. ft. In accordance with the findings of Decision 25282-D01-2020 the AUC directed AET, in its compliance filing, to reflect the AUC’s variance of the square footage to 200 000 sq.ft.

(j) Direction 41 – Allocation of Head Office Rent Costs – USA 931.1 Lease Costs

AET was directed in its compliance filing to identify the facilities leased and to provide the calculations showing how the forecast of $1.5 million has been derived. An adjustment was required to AET’s forecast rent costs related to USA 931.1 lease costs. AET was directed to provide a revised Attachment 1 to Direction 41 that uses the AET’s share of total 2017 facility headcount to determine AET’s share of rent for each of the facilities.

(k) Directions 3, 4, 7, 10, 16, 35, 40

The AUC was satisfied that AET complied by these Directions.

Kearl Line Relocation

In Decision 25282-D01-2020 the AUC granted AET's request to treat the Kearl Line as system costs. The AUC directed AET to include its forecast costs for the Kearl Line relocation in its consolidated filing to reflect this adjustment of Decision 22742-D01-2019.

Compliance with Decision 22742-D02-2019 – Fort McMurray Wildfire

Decision 22742-D02-2019 contained three directions in dealing with utility asset disposition and other matters pertaining specifically to the Fort McMurray wildfire. The AUC varied Directions of that decision in Decision 25319-D01-2020.

The AUC directed that if there was a second compliance filing to the 2018-2019 GTA, AET was to update its supporting schedules in accordance with the findings in Decision 25139-D01-2020. AET was therefore directed to update its supporting schedules to comply with the directions, as amended by Decision 25139-D01-2020, in its consolidated filing.

***AESO Approval of New and Amended Alberta Reliability Standard Definitions,* AUC Decision 25702-D01-2020**

Alberta Reliability Standard Definitions

On July 3, 2020, pursuant to Section 19(4)(b) of the *Transmission Regulation*, the Alberta Electric System Operator ("AESO") forwarded proposed changes to certain Alberta reliability standard definitions ("ARS") to the AUC for review and recommended their approval.

In this decision, the AUC approved the new ARS-related definition of "radial circuit" and amendment of the ARS-related definitions of "system access service" and "bulk electric service".

No objections were filed with the AUC by the July 22, 2020 deadline specified in the July 8, 2020 notice of filing and notice for objection issued by the AUC.

Background

In its forwarding notice, the AESO submitted that the proposed changes to reliability standard definitions are primarily the result of the current "bulk electric system" definition being quite general, and lacking clarity and specificity. The proposed amendments to the "bulk electric system" definition would allow the relevant sections of these reliability standards to be simplified.

The AESO explained that the proposed new "radial circuit" definition was being proposed for use in the "bulk electric system" definition. The term "system access service" was being used in the ISO tariff, and was being proposed for use in the reliability standards.

Findings and Decision

The AUC was satisfied that the AESO consulted with those market participants likely to be directly affected and that the AESO did forward the proposed reliability standards to the AUC for review, thereby fulfilling the requirements of Section 19(4) of the *Transmission Regulation*.

The proposed reliability standard was not found to be technically deficient or not in the public interest. Therefore, the AUC followed the recommendation of the AESO pursuant to Sections 19(5) and 19(6) of the *Transmission Regulation* and approved the new and amended ARS-related definitions.

The approved new definition of "radial circuit" is as follows:

> an arrangement of contiguous system elements energized at 50 kV or higher that:

a) extend from a system element on the networked transmission system in a linear or branching configuration;

b) connect to one or more of a load facility, a generating unit, or an aggregated generating facility; and

c) comprise the only circuit by which power can flow between the networked transmission system and the facilities identified in item (b) under normal operating conditions,

and includes an arrangement where the circuit energized at 50 kV or higher is connected to another circuit energized at 50 kV or higher, either through a switching device that is operated normally open or through facilities energized at less than 50 kV where the circuit would be a radial circuit if the connection did not exist.

The approved new definition of “system access service” is as follows:

“System access service” means the service obtained by market participants through a connection to the transmission system, and includes access to exchange electric energy and ancillary services.

The approved amended definition of “bulk electric system” is:

“bulk electric system” means all system elements that are included in the following:

(a) all system elements that have all terminals energized at 100 kV or higher that are not part of a radial circuit;

(b) a radial circuit comprised of system elements that have all terminals energized at 100 kV or higher where the radial circuit connects to:

(i) any facility included in items (iv) through (vii) below; or

(ii) 2 or more generating resources, being generating units and aggregated generating facilities, that have a combined maximum authorized real power higher than 67.5 MW;

(c) a transformer that has its primary terminal and at least one secondary terminal energized at 100 kV or higher;

(d) a generating unit that has a maximum authorized real power higher than 18 MW where system access service is provided through a switchyard that is directly connected to transmission facilities energized at 100 kV or higher, including all system elements from the terminal of the generating unit to the transmission facilities energized at 100 kV or higher;

(e) an aggregated generating facility that has a maximum authorized real power higher than 67.5 MW where system access service is provided through a switchyard that is directly connected to transmission facilities energized at 100 kV or higher, including all system elements from the collector bus to the transmission facilities energized at 100 kV or higher, and excluding the generating units and the collector system feeders;

(f) all generating units and aggregated generating facilities where system access service is provided through a common switchyard that is directly connected to transmission facilities energized at 100 kV or higher and the generating units and aggregated generating facilities have a combined maximum authorized real power higher than 67.5 MW, including all system elements from the terminal of each generating unit and from the collector bus of each aggregated generating facility to transmission facilities energized at 100 kV or higher, and excluding the generating units and collector system feeders of each aggregated generating facility;

(g) a blackstart resource, including all system elements from the terminal of the blackstart resource to transmission facilities that are energized at 100 kV or higher; and

(h) a static or dynamic reactive power resource that is dedicated to supplying or absorbing reactive power to or from the transmission system and is connected:

(i) to transmission facilities energized at 100 kV or higher;

(ii) through a dedicated transformer that is directly connected to transmission facilities energized at 100 kV or higher; or

(iii) through a non-dedicated transformer that has its primary terminal and at least one secondary terminal energized at 100 kV or higher.

ENMAX Power Corporation 2018-2020 Transmission Owner General Tariff Application Compliance Filing to Decision 23699-D01-2020 (Corrigenda), **AUC Decision 25738-D01-2020**
Revenue Requirements

In this decision, the AUC granted an application by ENMAX Power Corporation ("ENMAX") for approval of its compliance filing to Decision 23966-D01-2020 ("Corrigenda"), ENMAX's 2018-2020 transmission facility owner ("TFO") general tariff application ("GTA").

Background

On July 17, 2020, ENMAX filed a compliance filing application with the AUC, pursuant to the AUC's order in Decision 23966-D01-2020 (Corrigenda). ENMAX requested approval of its compliance with directions from Decision 23966-D01-2020 (Corrigenda) regarding AUC's 2018-2020 transmission GTA.

ENMAX's Compliance Filing

In its compliance filing ENMAX requested approval of transmission revenue requirements of $83.89 million for 2018, $91.02 million for 2019, and $96.59 million for 2020 and an expedited compliance filing process in accordance with Bulletin 2016-18.

ENMAX stated, that in this application it complied with AUC directions 1, 2, 4, and 5 from Decision 23966-D01-2020 (Corrigenda).

Findings

In Direction 3 the AUC directed ENMAX to seek approval for the costs associated with the Substation No. 1 project, and to file a business case in support of that project, in a future GTA, after a decision had been rendered in the facilities proceeding. The AUC directed ENMAX to include all material on the record of this proceeding that relates to the Substation No. 1 project as part of its filing for its next GTA.

The AUC noted the response by ENMAX stating its commitment to include all materials of this proceeding related to the Substation No. 1 project in its next GTA.

The AUC accepted that Direction 3 given in Decision 23966-D01-2020 (Corrigenda) will remain outstanding and will be addressed at the time of ENMAX's next GTA.

The AUC was satisfied that ENMAX complied with the requirements Directions 1, 2, 4, and 5 in its compliance filing. The AUC was satisfied that for Direction 1, ENMAX would maintain the scope and language of its Major Storms and Natural Disasters deferral account as directed, and that for directions 2, 4 and 5, ENMAX reflected the required changes to its minimum filing requirement schedules and adjusted its revenue requirement amounts accordingly.

The AUC approved the revenue requirements for 2018-2020 as filed by ENMAX.

***Horseshoe Power GP Ltd. Gull Lake Cogeneration Power Plant Expansion Project*, AUC Decision 25044-D01-2020**

Conditional Approval - Application for Connection Closed - Application for Industrial System Designation Closed

In this decision, the AUC approved the application from Horseshoe Power GP Ltd. ("Horseshoe Power") to construct and operate a 5.9-megawatt ("MW") cogeneration power plant, designated as the Gull Lake Cogeneration Power Plant expansion (the "Power Plant Expansion" or the "Project"). The AUC closed Horseshoe Power's applications for a connection order and for an industrial system designation ("ISD").

<u>Introduction</u>

Horseshoe Power owns and operates a six-MW Gull Lake Cogeneration Power Plant in the County of Lacombe, near Gull Lake. In Order 23404-D03-2018 the connection of the power plant to FortisAlberta Inc.'s ("Fortis") distribution system was approved.

The Power Plant Expansion would involve the construction and operation of four 1.475-MW natural gas engine-driven electric power generating units. The proposed power plant expansion would use natural gas to generate electricity for export to the Alberta Interconnected Electric System ("AIES") and would co-generate carbon dioxide and steam for use by a future greenhouse.

Fortis submitted a statement of Intent to participate ("SIP") and later stated, it did not support the Project in its current configuration. Following information requests and clarification of the application, Fortis filed a letter of non-objection to the Project, limiting its effect to the technical aspect of the proposed interconnection. Fortis' submissions indicates that its concerns with the Project related to the connection order and ISD applications. Fortis' concerns with the connection application pertained to uncertainty with Horseshoe Power's proposal. Its concerns with the ISD application pertained to Horseshoe Power's intention to build its own distribution line to connect the Power Plant Expansion with its industrial operations located across Highway 792 and whether the Project meets the requirements for an ISD under Section 4 of the *Hydro and Electric Energy Act ("HEEA").*

The AUC found it unnecessary to rule on Fortis's standing in this proceeding because Fortis did not object to the Power Plant Expansion and the AUC closed Horseshoe Power's connection application and its ISD application.

Sections 11 and 18 of the *HEEA* and Section 17 of the *Alberta Utilities Commission Act* were relevant to the AUC's consideration of the application for the Power Plant Expansion.

Section 4 of the *HEEA* was relevant to the AUC's consideration of the ISD application.

<u>Application to Construct and Operate a 5.9-MW Power Plant</u>

A noise impact assessment ("NIA") for the proposed Power Plant Expansion was completed in accordance with Rule 012: *Noise Control*. The NIA concluded that the predicted cumulative sound levels at each receptor comply with the permissible sound levels set out in Rule 012.

Horseshoe Power stated that noise mitigation measures were installed on the existing generators, including sound insulation for the generator enclosures, building, and acoustic silencers for the inlets, outlets and engine pipes. It added that similar noise mitigation measures would be installed on the new generators to ensure compliance of the proposed power plant with Rule 012.

Horseshoe Power stated that the Project would have no ground, water, or wildlife impact. It stated all associated fertile areas would be mowed or sprayed for weed control to prevent and control weeds from forming on the expansion site and spreading to adjacent agricultural lands. A pre-disturbance nest search survey would be conducted and Alberta Environment and Parks' ("AEP") recommended minimum setback distances and restricted activity dates would be abided by.

Horseshoe Power stated that the emissions from the proposed power plant expansion would comply with the current provincial emissions standards and the *Alberta Ambient Air Quality Objectives and Guidelines.*

Findings

The AUC found that Horseshoe Power's participant involvement program satisfied the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*.

The AUC conditioned the approval of the power plant upon Horseshoe Power's submission of confirmation of an updated *Historical Resources Act* approval no later than 30 days before the start of construction. The AUC also required Horseshoe Power to submit confirmation of AEP's approval of its updated air emissions assessment no later than 30 days before the start of construction.

The AUC was satisfied with the submitted NIA and accepted Horseshoe Power's commitment to install appropriate mitigation measures on the proposed generators to ensure compliance with Rule 012.

Application to Connect the Proposed Power Plant Expansion to the Alberta Interconnected Electric System

Horseshoe Power did not provide a statement from the distribution facility owner indicating that it was willing to connect the generating facilities, as required of an applicant who wishes to connect a power plant to the AIES at a distribution voltage level by Rule 007. Therefore, Horseshoe Power did not provide the information required by requirement IC1 in Rule 007. The AUC considered the information required in Rule 007's IC1 to be critical to its assessment of a connection application, and that the absence of the required statement from Fortis was a deficiency that was material to the application. The connection application was accordingly closed.

Application for an Industrial System Designation

Horseshoe Power requested an ISD encompassing the Gull Lake Cogeneration Power Plant and the proposed power plant expansion.

Horseshoe Power stated that up to 10 MW could be supplied from the industrial system to the AIES.

Horseshoe Power submitted an economic assessment for the proposed power plant expansion showing that it expected to earn $2,096,600 in revenue from the sale of electric energy to the AIES on an annual basis, based on a power pool price of $55/MWh.

Findings

The AUC considers the principles and criteria found in Section 4 of the *Hydro and Electric Energy Act* when considering an application for an ISD. Section 4 permits an ISD where the development of on-site generation was a component of an efficient, highly integrated industrial process where on-site generation represents the most economical source of generation for on-site operations. The application must meet the information requirements of Rule 007.

In the absence of an application with meaningful, reliable and verifiable responses to the information requirements of Rule 007, the AUC was unable to determine whether Horseshoe Power's application for an ISD reflects the development of on-site generation as a component of an efficient, highly integrated industrial process that represents the most economical source of generation for on-site operations.

The AUC closed the application for an ISD.

***Neyaskweyahk Sundancer Solar Project,* AUC Decision 25626-D01-2020**
Small Scale Generation Regulation - Community Generating Unit

In this decision, the AUC approved an application from Neyaskweyahk Sundancer LP ("Neyaskweyahk") to qualify the 0.99-megawatt ("MW") Neyaskweyahk Sundancer Solar Project ("the Project") as a community generating unit.

Background

Neyaskweyahk filed an application with the AUC for approval to qualify the Project as a community generating unit, pursuant to Section 3 of the *Small Scale Generation Regulation*.

A notice of application was not issued, and a hearing was not required as the AUC considered, that the decision on the qualification of the project as a community generating unit would not directly and adversely affect the rights of a person pursuant to Section 9 of the *Alberta Utilities Commission Act.*

Neyaskweyahk provided invoices totalling $55,925.00 for Rodan Energy Solutions to supply and install the revenue metering system, and $13,530.22 for Blue Mountain Power Co-op to supply and install the primary meter pole and associated equipment.

In response to an information request from the AUC, Neyaskweyahk clarified that it had not yet completed noise impact analyses ("NIA") for the project as it was contemplating a Phase 2 expansion of the project, which would increase the total capacity of the project beyond one MW and require an application under Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*, including a complete NIA. Neyaskweyahk submitted that a NIA would be conducted in support of the Rule 007 application for the Phase 2 expansion, and that this NIA would also verify noise compliance of the existing Phase 1 project.

Findings

Neyaskweyahk filed its application in the form established by the AUC and included a community benefits statement with its application as required. The Project is owned by Ermineskin Cree Nation through a wholly owned subsidiary. Ermineskin Cree Nation is a community group as defined in Subsection 1(e) of the *Small Scale Generation Regulation*. The application was found to satisfy the requirements of the *Small Scale Generation Regulation*.

After subtracting the costs to install and commission the metering system, the AUC determined that the cost to purchase the meter was $61,782.10.

The AUC accepted Neyaskweyahk's submission that the Project's noise levels were very low, and likely comply with permissible sound levels set out in Rule 012. The AUC expected Neyaskweyahk to file a NIA in accordance with Rule 012 in its future Phase 2 application, which would address noise compliance of the entire project.

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

***ATCO Gas 2020 Weather Deferral Account Rate Rider W North and South,* AUC Decision 25666-D01-2020**
WDA Rate Rider Application

In this decision, the AUC approved the North and South weather deferral account ("WDA") rider, Rate Rider W, of ATCO Gas for implementation during the period of September 1, 2020 to April 30, 2021.

Background

On June 16, 2020, ATCO Gas filed an application with the AUC requesting approval for a 2020 Rider W effective September 1, 2020, to April 30, 2021, for the refund of its North WDA and South WDA balances as of April 30, 2020, resulting in a refund of approximately $8.203 million and $9.952 million, respectively.

In calculating the WDA balances, ATCO Gas applied monthly carrying charges to the WDA, which are based on ATCO Gas's weighted average cost of capital ("WACC)" using the most recent approved capital structure.

ATCO Gas followed the directions issued by the Commission from Decision 24665-D01-2019. ATCO Gas provided the derivation of the annual WACC carrying cost rate, including annual WACC calculations from 2017 to 2019. ATCO submitted that it revised the presentation of the WDA calculations, stating that the WDA calculations for North and South "are summarized in a more efficient manner, while still including the necessary information and data for the calculations".

Findings

The AUC found the methodology used to determine the WDA balances and the 2020 Rider W to be consistent with the methodology and threshold requirements approved by the AUC in past WDA rate rider applications.

ATCO Gas provided evidence that a refund period of eight months would have minimal bill impact on customers. The 2020 Rate Rider W will change rates by less than three percent over both rate groups over the refund period. The AUC noted that the customers of both ATCO Gas North and ATCO Gas South will receive refunds and considered that the amounts are low enough that when the refund periods expire, no rate instability would result in terms of impacts to customers. Accordingly, the AUC was satisfied, that the implementation of the 2020 Rider W as proposed by ATCO Gas would not result in rate shock or rate instability.

The AUC was satisfied that it would be beneficial that the refund period for the 2020 Rider W end on April 30, 2021. This would minimize any confusion as to whether a new Rider W has been triggered solely due to weather effects, or because the WDA balance exceeded the threshold partly because the previous Rider W has not been fully refunded or recovered.

Accordingly, the AUC approved the WDA refund of $8.203 million to ATCO Gas North customers and $9.952 million to ATCO Gas South customers by way of the 2020 Rider W from September 1, 2020, to April 30, 2021.

***Amended Rule 006: Rules on Regulatory Audits*, AUC Bulletin 2020-29**

Minor Amendments - Modernization

On July 28, 2020, the AUC approved an amended Rule 006: *Rules on Regulatory Audits*. This amended rule, with links to related information, can be found on the AUC website. The effective date of the amended Rule 006 was August 3, 2020.

The AUC chose to modernize the rule to update the language of the rule, to correct references to account for current audit standards, and to reflect the new responsibilities of the AUC.

The amendments were considered to be minor, would facilitate streamlining opportunities, and were made without stakeholder consultation.

***Revised Draft Version of AUC Rule 007 and Interim Changes to AUC Participation Involvement Program*, AUC Bulletin 2020-30**

Stakeholder Feedback - Participant Involvement

The AUC asked for stakeholder feedback on proposed amendments to AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("Rule 007") to address emerging technologies and rising issues identified in Bulletin 2019-10 and Bulletin 2019-19. Feedback was also sought on reorganizing Rule 007 to eliminate duplication, clarify existing requirements and to make the rule easier to understand and to use.

The draft version of Rule 007 explicitly references Indigenous groups throughout the information requirements and in the participant involvement program ("PIP") guidelines.

Interim Changes to AUC Participation Involvement Program; Related Information Requirements Updated

The AUC extended the period to receive, consider and respond to project notifications from 14 days to 30 days for Rule 007 Appendix A1, Section 6 and Appendix A2, Section 3.2(c); Rule 020: *Rules Respecting Gas Utility Pipelines*, Section 2.2(4). The AUC continued to consider this additional time to be reasonable in the current circumstances related to COVID-19.

The AUC also discouraged face-to-face consultation unless it could be undertaken in compliance with physical distancing practices. The AUC continues to encourage applicants to communicate with stakeholders using phone, email, video conferencing or other means that avoid face-to-face contact wherever possible. Project proponents could assess, on a case-by-case basis, whether gatherings such as open houses and town hall meetings are prudent and may hold them where consistent with current government orders related to COVID-19.

Indigenous Engagement

The AUC asked Applicants to continue to reach out to Indigenous groups to understand their unique circumstances and availability to discuss proposed electric and gas utility facilities under Rule 007 and Rule 020.

CANADA ENERGY REGULATOR

Manitoba Minnesota Transmission Project (MMTP or Project) Certificate EC-059, Condition 3 – Implementation of Commitments, and Condition 15, Commitments Tracking Table, **CER Letter Decision**
Compliance - Conditions

In this decision, the CER found that Manitoba Hydro complied with Conditions 3 and 15 of the Certificate of Public Convenience and Necessity EC-059 permitting Manitoba Hydro to operate the Project (the "Certificate"). The CER found that, because Manitoba Hydro demonstrated compliance with the Certificate, there is no basis to grant the relief sought by the Manitoba Métis First Nation ("MMF").

Background

The final Condition 3 required Manitoba Hydro implement all policies, practices, mitigation measures, recommendations, and procedures for the protection of the environment and promotion of safety referred to in its application, or as otherwise agreed to in its related submissions as well as commitments made to Indigenous groups through its project application or otherwise on the record of EH-001-2017.

The final Condition 15 required Manitoba Hydro file with the NEB and post on its website, at least thirty days prior to commencing construction, a commitments tracking table listing all commitments made in its application, including all commitments made to Indigenous communities, and otherwise agreed to during questioning or in its related submissions in the NEB's EH-001-2017 proceeding, as well as commitments from the Clean Environment Commission hearing process that are of federal interest.

MMF and Manitoba Hydro Submissions

In its 23 July 2019 letter, the MMF submitted that it and Manitoba Hydro negotiated a series of documents, including:

- Kwaysh-kin-na-mihk la paazh Agreement/Turning the Page Agreement ("TPA");
- a contract, consisting of a workplan and contribution agreement and leading to a Métis Traditional Knowledge and Land Use Study (the "Contract"); and
- the July 2017 Agreement/Major Agreed Points ("MAP"), based on the TPA, and the Contract, as well as addressing documented impacts of the Project on Aboriginal Rights of Métis.

The TPA, Contract and MAP is collectively referred to as the "MAP Documents".

The MMF asserted that Manitoba Hydro:

- was breaching Condition 3 by refusing to acknowledge, honour and implement the MAP, as a clear commitment to the MMF that falls within the scope of Condition 3;
- failed to perform Step 6 mitigation measures in the Contract, including meeting to find alternatives ways to address impacts if the Contract is not implemented;
- failed to include the MAP Documents, specifically the MAP and the Contract, as commitments in the Commitment Tracking Table required to be filed pursuant to Condition 15; and
- omitted a key component of its commitment to the MMF for 10 percent Métis construction content in the Project.

The MMF requested ensuring that Manitoba Hydro complies and fulfills Conditions 3 and 15.

Preliminary Matters

Submissions Filed Outside the CER Established Process

The CER considered submissions made by both parties to consider that processes to evaluate condition compliance are set on a case-by-case basis and should allow for fulsome evaluation of potential non-compliance issues. In the CER's view, the opportunities for participation afforded to both the MMF and Manitoba Hydro were appropriate in the circumstances.

Scope of Documents in Dispute

The CER noted that what was in dispute was whether the MAP Documents, and particularly the MAP itself, were commitments within the meaning of Condition 3 of the Certificate. The CER needed to consider if these are commitments and therefore needed to appear in the Commitments Tracking Table required by Condition 15.

The CER considered whether Conditions 3 and 15 apply to the MAP Documents in their entirety, but not where certain element related to the Contract, are commitments made by Manitoba Hydro, within the meaning of Condition 3.

Reasons for the Commission Decision that the Map Documents are not a Commitment Pursuant to Conditions 3 and 15 of Certificate EC-059

The CER found that the MAP Documents are not a commitment within the meaning of Condition 3. As a result, Manitoba Hydro is not required to include any of the MAP Documents in the Commitments Tracking Table under Condition 15.

Commitments Made by Manitoba Hydro on the Record of the EH-001-2017

The CER noted, that, to find that the MAP Documents must be implemented by Manitoba Hydro pursuant to this Project approval, there must be persuasive evidence that the MAP Documents were a commitment made by Manitoba Hydro through its application or otherwise on the record before the NEB in the EH-001-2017 proceeding.

The CER examined the application and the relevant portions of the record from EH-001-2017 and noted that Manitoba Hydro did not record or offer any commitment to implement the MAP Documents. The CER noted that Manitoba Hydro took steps to record its position that the Map Documents, and the MAP itself, were neither binding nor part of its application before the NEB.

The CER understood the MMF submission to mean that the inclusion of the MAP in the information request response means that the MAP Documents are a commitment made by Manitoba Hydro in EH-001-2017. This interpretation by MMF is not supported by an overall plain reading of Condition 3. The CER viewed that, pursuant a plain reading of Condition 3 only Manitoba Hydro could make a commitment on behalf of itself.

Condition 15

Condition 15 requires Manitoba Hydro to submit to the CER, and update, a commitment tracking table that includes "all commitments made in its application, including all commitments made to Indigenous communities, and otherwise agreed to during questioning or in its related submissions in the NEB's EH-001-2017 proceeding". Condition 15 is intended to enhance transparency regarding Manitoba Hydro's performance of commitments but did not add substantive obligations that Manitoba Hydro is required to fulfill. Regarding Condition 15, the CER noted that Manitoba Hydro has not listed the MAP Documents as a commitment to be tracked.

Legal Proceedings Commenced by the MMF in Relation to the MAP

The dispute between the MMF and Manitoba Hydro regarding the MAP Documents and other agreements entered into by Manitoba Hydro with Indigenous peoples lead to litigation before the Manitoba Court of Queen's Bench, in relation to which the NEB received submissions. In the EH-001-2017 hearing, the NEB heard submissions related to the legality of these agreements. Manitoba Hydro submitted that the NEB could not address the legality of the agreements between Manitoba Hydro the MMF and other Indigenous peoples, which was already a matter before the Manitoba Court of Queen's Bench. The NEB agreed with that position. The CER adopted that ruling by the NEB and expressly refrained from exploring the enforceability or legality of these MAP Documents and other agreements.

Conclusion

The CER decided that the MAP Documents are not a commitment under Condition 3 and that they need not be listed as a commitment in the Commitment Tracking Table pursuant to Condition 15. The Commission found that the matter related to the percentage of construction tenders offered to Métis communities has been fully answered by Manitoba Hydro's update to its Commitment Tracking Table.

***AltaGas LPG General Partner Inc., on Behalf of AltaGas LPG Limited Partnership Application for a 25-Year Licence to Export Propane*, CER Letter Decision**
Surplus Determination - New Export Licence

In this decision, the CER decided, pursuant to Section 344 of the *Canadian Energy Regulator Act* ("*CER Act*"), to issue a 25-year Licence to AltaGas Limited Partnership ("AltaGas"), subject to the approval of the Minister of Natural Resources, to export propane subject to the terms and conditions described in Appendix I to the letter decision. Further, the CER decided that the term of the Licence would commence upon Ministerial approval.

Background

On November 28, 2019, AltaGas applied to the CER, pursuant to Section 344 of the *CER Act*, for a licence to export propane seeking:

- a 25-year Licence to export propane, starting on the date of first export;
- including a 15% annual tolerance, a maximum annual export quantity of 2,669,391 cubic metres ("m^3") or 16,790,000 barrels ("bbls");
- a maximum quantity of 66,734,775 m^3 or 419,750,000 bbls of propane over the term of the Licence;
- the point of export of propane from Canada to be a marine export terminal located near Prince Rupert, B.C. and points along the Canada - United States border where railway crossings occur (specifically: Lacolle, Quebec; Emerson, Manitoba; North Portal, Saskatchewan; Coutts, Alberta; Kingsgate, British Columbia; Huntingdon, British Columbia; and White Rock, British Columbia); and
- an "early expiration clause" where, unless otherwise directed by the Commission of the CER, the term of the Licence ends 10 years after the date of issuance of the licence if the export of propane has not commenced on or before that date.

AltaGas responded to an information request ("IR") from the CER, stating that it had no business reason for selecting a new long-term export Licence instead of applying to vary (or revoke and reapply for) GL-338 to reflect increased volumes and additional export points.

Surplus Determination

In response to and CER IR, AltaGas submitted that the quantity of propane it would export would not exceed the surplus remaining after due allowance was made for the reasonably foreseeable requirements for use in Canada having regard to the trends in the discovery of gas in Canada. In support of this submission, AltaGas submitted two studies: (1) *Canadian Propane Supply and Demand through 2055* by Goobie Tulk Inc. ("GTI Report"), and (2) *AltaGas LPG General Partner Inc. Propane Export Licence Application: Implications and Surplus Assessment Report* by Mr. Roland Priddle ("Priddle Report").

The Priddle Report describes Canadian and North American natural gas resources as very large and indicates it was reasonable to assume that the amount of propane, preponderantly a product of gas processing, that could be available to market from those resources is also likely very large.

The GTI Report provides three scenarios of propane supply that show Canadian propane production growing over the forecast period, with this growth dependent on liquefied natural gas ("LNG") export projects coming on-stream. GTI provided a no-LNG ("GTI Base") forecast and two LNG scenarios for propane production: ("GTI LNG 1") and ("GTI LNG 2").

GTI expected propane supply in Canada to grow from 244.1 thousand barrels per day (Mb/d) in 2018 to 321.2 Mb/d in 2023 in all three scenarios. By 2055, propane supply would grow to 336.4 Mb/d (GTI Base), 410.1 Mb/d (GTI LNG 1), and 497.3 Mb/d (GTI LNG 2). The GTI Report anticipates relatively steady growth of domestic propane demand in Canada over the forecast period. In its GTI Base scenario, the forecast shows Canadian propane demand of 103.5 Mb/d in 2018 growing to 178.5 Mb/d in 2055. In its GTI LNG 1 scenario, the forecast shows Canadian propane demand growing to 190.3 Mb/d in 2055.

The Priddle Report notes that propane prices would continue to be formed competitively by market forces balancing supply and demand within supportive policy and regulatory frameworks. Canadians would always be able to meet their propane requirements at market-determined prices. The Priddle Report concludes that it was relevant to add that the export of the propane in this Application was unlikely to affect the potential for short-term propane market disruptions in the Canadian and North American industry.

Views of the Commission

According to Section 345 of the *CER Act*, it is the CER's role to assess whether gas proposed to be exported exceeds the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to trends in the discovery of gas in Canada. In fulfilling this mandate, the CER recognized that Canadian propane requirements were met in the context of free trade within a North American energy market.

The CER accepted the AltaGas' analysis of current and forecasted Canadian propane demand and its assessment that Canadian propane requirements would be met over the term of the Licence, given the resource base and the integrated nature of the North American propane market.

The CER accepted the position presented in the GTI Report and the Priddle Report that the North American propane market is generally liquid, open, efficient, integrated and responsive to changes in supply and demand.

The CER monitors Canada's NGL supply and demand, including propane and other NGL developments. Monitoring assists the CER in identifying where markets may not be functioning properly or where the evolution of supply and demand casts doubt on the ability of Canadians to meet future energy requirements. The CER noted that the evidence in this Application is generally consistent with the CER's current market monitoring.

Commencement of Term of Licence and Issuance of Single Licence

The CER considered whether any exports or propane by AltaGas should occur under the authority of one licence, by varying the existing GL-338, or two licences, by issuing a standalone new Licence.

The CER issued, subject to Ministerial approval, a new Licence to AltaGas, as GL-338 and GL-344 have different terms and some different export points, and to promote administrative efficiency in the reporting and monitoring of exports.

Relief from Filing Requirements

AltaGas requested relief from the information requirements for propane, butanes, or ethane export applications set out in Section 20 of the *National Energy Board Act Part VI (Oil and Gas) Regulations* ("Part VI Regulations"), except where those requirements are addressed within the Application.

The CER was satisfied that AltaGas met the filing requirements of Section 20 of the Part VI Regulations and the CER found that AltaGas showed that it was unable to provide further information.

The CER recognized that not all filing requirements contained in Section 20 of the Part VI Regulations were relevant to its assessment of this Application. Therefore, the Commission exempted AltaGas from the filing requirements contained in Section 20 of the Part VI Regulations that were not included in the Application.