REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

This monthly report summarizes matters under the jurisdiction of the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC") and the Canada Energy Regulator ("CER") and proceedings resulting from these energy regulatory tribunals. For further information, please contact a member of the RLC Team.

Regulatory Law Chambers ("RLC") is a Calgary based boutique law firm, specializing in energy and utility regulated matters. RLC works at understanding clients' business objectives and develops legal and business strategies with clients, consistent with public interest requirements. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

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ALBERTA ENERGY REGULATOR

***Nonroutine Commingled Abandonment*, AER Bulletin 2020-20**
Bulletin - Abandonment

In this Bulletin the AER discussed nonroutine commingled abandonment. Any abandonment activity that varies from the requirements given in *Directive 020: Well Abandonment*, is considered "nonroutine" and must be approved by the AER before work can be started. Requests for nonroutine abandonment of commingled wells have not generally been approved, primarily because the risks were not understood well enough.

In 2019 the AER undertook a study of those risks, and published *Open File Report 2019-06: A Risk-Based Methodology for Commingled Well Abandonment – Southeastern Alberta Gas Field Case Study*. In April 2019 the AER initiated a pilot under the Area-Based Closure program that began approving nonroutine abandonment of commingled wells meeting certain criteria. The pilot was ended and the AER will continue to review requests for nonroutine abandonment of commingled wells. The AER limited consideration to pools that are located below the base of groundwater protection and include intervals classified as low risk (green) in *Open File Report 2019-06*.

ALBERTA UTILITIES COMMISSION

***Red Deer Application for 2021 Interim Transmission Facility Owner Tariff,* AUC Decision 25862-D01-2020**
Rates

In this decision, the AUC approved the application by the City of Red Deer ("Red Deer") for its 2021 interim transmission facility owner ("TFO") tariff. The AUC approved the interim refundable TFO tariff of $439,583 per month.

Introduction

In its application for the 2021 interim and refundable TFO tariff, Red Deer requested continuation of the approved 2020 tariff of $439,583 per month on an interim and refundable basis until the AUC approved a revised interim or final tariff.

Findings

In decision 24451-D01-2019, the AUC approved an annual TFO tariff revenue requirement for Red Deer in the amount of $4.853 million for 2018, $5.105 million for 2019, and $5.275 million for 2020. The 2020 approved TFO tariff revenue requirement represented a monthly charge to the Alberta Electric System Operator ("AESO") of $439,583, effective January 1, 2020, to December 31, 2020.

The final 2021 TFO tariff would not be approved and in place before January 1, 2021, there was no opposition to the application or evidence of prejudice to customers, and the interim rate would promote regulatory efficiency and short-term rate stability. Based on this the AUC found Red Deer's request to continue with its approved 2020 TFO tariff on an interim refundable basis to be reasonable.

The AUC held that the 2021 interim refundable TFO tariff approval shall remain in effect until replaced by a revised interim or final tariff.

City of Lethbridge Application for 2021 Interim Transmission Facility Owner Tariff, AUC Decision 25868-D01-2020
Rates

In this application, the AUC approved the application by the City of Lethbridge ("Lethbridge") for the 2021 interim and refundable transmission facility owner ("TFO") tariff. The AUC approved Lethbridge's 2021 interim and refundable TFO tariff of $759,137 per month.

Introduction

In the application for the 2021 interim and refundable TFO tariff, Lethbridge requested continuation of its approved 2020 tariff of $759,137 per month on an interim and refundable basis until such time as the AUC approved either a revised interim or a final tariff.

Findings

In Decision 25570-D01-2020, the AUC approved an annual TFO tariff revenue requirement for Lethbridge in the amount of $8,104,200 for 2018, $8,651,200 for 2019 and $9,109,600 for 2020. The 2020 approved TFO tariff revenue requirement represented a monthly charge to the Alberta Electric System Operator ("AESO") of $759,137, effective January 1, 2020, to December 31, 2020.

A final 2021 TFO tariff would not be approved and in place before January 1, 2021, there was no opposition to the application or evidence of prejudice to customers, and the interim rate would promote regulatory efficiency and short-term rate stability. Based on this the AUC found Lethbridge's request to continue with its approved 2020 TFO tariff on an interim refundable basis to be reasonable.

The AUC found that the 2021 interim refundable TFO tariff approval shall remain in effect until replaced by a revised interim or final tariff.

***Suncor Energy Inc. Base Plant Industrial System Designation Amendment*, AUC Decision 25744-D01-2020**
Industrial System Designation - Amendment

In this decision, the AUC approved an application from Suncor Energy Inc ("Suncor") to amend its Base Plant Industrial System Designation ("ISD").

Introduction

Suncor applied to amend the ISD to include the approved but not constructed Inglis Island 806-megawatt ("MW") cogeneration power plant and associated transmission facilities.

Discussion

Suncor's existing industrial system contains five steam turbine generators and seven gas turbine generators with a combined capability of approximately 900 MW, producing gross generation of approximately 700 MW. Suncor requested approval to include the following systems in its ISD:

- Inglis Island Power Plant, which is comprised of two 403-MW natural gas turbine generators;
- Inglis Island Substation (29EDD-60), which includes one 260/15.5-kilovolt (kV), 300/400/500-megavolt ampere (MVA) transformer and associated substation equipment;
- Stone Island Substation (29EDD-61), which includes one 260/15.5-kV, 300/400/500-MVA transformer and associated substation equipment, and
- Two 260-kV transmission lines designated as 29PL9-24 and 29PL9-25.

With the inclusion of the Inglis Island Power Plant, the industrial system would have a total capability of over 1,700 MW. Suncor submitted that up to 1,265 MW of that would be available to be exported to the Alberta Interconnected Electric System ("AIES").

Findings

The AUC considered principles set out in subsection 4(2) of the *Hydro and Electric Energy Act* concerning the development of an economical supply of electricity in its decision to amend the ISD. The AUC considered that the energy produced by the Inglis Island Power Plant would be predominantly exported to the AIES rather than used to serve the on-site load.

The AUC found that the proposed industrial system facilitates the economical supply of generation that meets all the energy requirements of Suncor's integrated industrial processes.

The AUC noted that the existing facilities would continue to serve a significant amount of on-site load, and found that as a whole, the industrial system would result in reduced transmission losses. The AUC accepted Suncor's submissions that:

- Spare capacity existed on the transmission system in the Fort McMurray area and the project would not trigger incremental system upgrades; and
- The project would help maintain voltage stability, and would provide frequency support, and improve system inertia.

Pursuant to Section 4 of the *Hydro and Electric Energy Act* and sections 2(1)(d) and 117 of the *Electric Utilities Act*, the AUC approved the application.

Alberta Electric System Operator Needs Identification Document Application, AltaLink Management Ltd. Facility Applications - Cascade Power Plant Connection, AUC Decision 25689-D01-2020
Needs Identification Document - Facility Application

In this decision, the AUC approved the needs identification document ("NID") application from the Alberta Electric Systems Operator ("AESO") for the need to connect the Cascade Power Plant to the Alberta Interconnected Electrical System ("AIES"). The AUC further approved the applications from AltaLink Management Ltd. ("AltaLink") to relocate a portion of existing transmission lines, to alter the Bickerdike 29s Substation, and to construct and operate three single-circuit 240 kilovolt ("kV") transmission lines.

<u>Discussion</u>

NID Application

The AESO stated that it received a system access service request from Cascade Power Project Limited Partnership to connect the approved 900-megawatt ("MW") Cascade Power Plant and the associated Whisky Jack 1047S Substation to the transmission system in the Edson area. The AESO submitted that the request could be met by adding three 240-kV transmission lines from the Whisky Jack 1047S Substation to the existing Bickerdike 39S Substation and modifying the Bickerdike 39S Substation.

Facility Applications

AltaLink proposed to:

- Construct and operate three single-circuit, 240 kV transmission lines designated as transmission lines 1084L, 1135L and 1168L, from Cascade Power's approved Whisky Jack 1047S Substation to AltaLink's existing Bickerdike 39S Substation;

- Relocate between 200 and 800 metres of the existing 973L, 974L, 874L, and 740L transmission lines; and

- Alter the existing Bickerdike 39S Substation by adding four 240 kV circuit breakers and expanding the fence line of the substation.

AltaLink estimated the cost of the project to be $16.1 million with all costs allocated to Cascade Power. The target in-service date for the project is March 25, 2022.

<u>Findings</u>

The AUC was satisfied that the NID application filed by the AESO contains all the information required by the *Electric Utilities Act* ("*EUA*"), the *Transmission Regulation,* and *Rule 007*. The AUC considered the AESO's assessment of the need to be in accordance with subsection 38(e) of the *Transmission Regulation*, and approved the AESO's NID application.

The AUC found that the facility applications filed by AltaLink complied with the information requirements prescribed in Rule 007. The facility applications were also consistent with the need identified in the AESO's NID application.

The AUC was satisfied that the joint participant involvement program undertaken by the AESO and AltaLink met the requirements of Rule 007.

Pursuant to Section 34 of the *EUA*, the AUC approved the need outlined in NID Application 25689-A001 of the AESO. Pursuant to sections 14, 15, 18, and 19 of the *Hydro and Electric Energy Act*, the AUC approved the facility applications of AltaLink.

Alberta Electric System Operator Needs Identification Document Application, AltaLink Facility Application - Windrise Connection Project and Windy Flats 138S Substation Alteration, AUC Decision 25074-D01-2020
Needs Identification Document - Facility Application

In this decision, the AUC considered four applications by three parties:

- Application 25074-A001 by the Alberta Electric System Operator ("AESO") for approval of the needs identification document ("NID") for the Windrise Connection Project;
- Application 25074-A002 by Windrise Wind Energy Inc. ("Windrise") for approval to construct and operate a 138-kilovolt ("kV") transmission line, designated as Transmission Line 497L, from Windrise 1063S Substation to Windy Flats 138S Substation;
- Application 25074-A003 by AltaLink Management Ltd. ("AltaLink") for approval to alter Windy Flats 138S Substation; and
- Application 25074-A004 by Windrise for approval to connect Transmission Line 497L to Windy Flats 138S Substation.

The AUC advised that it would decide on Windrise's applications 25074-A002 and 25074-A004 in a separate decision on or before November 16, 2020.

Introduction

The AESO and AltaLink co-ordinated their applications with the application from Windrise to construct, operate and connect a 138-kV transmission line from the Windrise 1063S Substation to the Windy Flats 138S Substation, and requested that the AUC consider the applications in a single proceeding as contemplated in Section 15.4 of the *Hydro and Electric Energy Act* ("*HEEA*").

In response to the notice of application, the AUC received five statements of intent to participate ("SIPs") and became aware of an error in the map appended to its notice of application. It issued a revised notice of application and received additional SIPs from two landowners.

Discussion

NID Application

The AESO received a system access service request from Windrise Wind L.P. by its general partner Windrise, a wholly owned subsidiary of TransAlta Corporation, to connect its Windrise Wind Power Project to the Alberta Interconnected Electric System ("AIES"). Windrise requested a new rate supply transmission service with a contract capacity of 207 MW and a new rate demand transmission service with a contract capacity of 3 MW.

The AESO determined that the preferred option to address the request involved upgrading AltaLink's existing Windy Flats 138S Substation to accommodate the addition of a 138-kV transmission line to connect Windrise's approved Windrise 1063S Substation to Windy Flats 138S Substation.

In response to concerns and an information request regarding the number of existing transmission lines located in the vicinity, the AESO explained it had explored upgrading existing transmission lines to accommodate the system access service request, but that this would require greater overall transmission infrastructure development. The AESO also indicated that it considered proposing a higher capacity transmission line between the Windrise 1063S and Windy Flats 138S substations in anticipation of future generation facilities, but in the absence of other projects requesting connection, this was unjustifiable.

Substation Alteration Application

AltaLink requested approval to install one 240/138-kV, 240/320/400-megavolt ampere transformer, one 138-kV circuit breaker, and associated equipment. AltaLink stated that the modifications would occur within the existing substation fence line and all construction would occur on land owned by AltaLink.

AltaLink received *Historical Resources Act* approval for the alteration and conducted a noise impact assessment that determined cumulative sound levels would not exceed the allowances of Rule 012: *Noise Control*.

Findings

AESO's NID Application

The AUC found the NID application included all the information required by the *Electric Utilities Act* ("*EUA*"), the *Transmission Regulation* and Rule 007*: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments.*

The AUC acknowledged intervener concerns regarding transmission line proliferation. The AUC accepted the AESO's conclusion that alternative options were rejected for sound reasons, including that they would require additional transmission development overall. The interveners filed no evidence to counter this assertion.

The AUC considered the AESO's assessment of the need to be correct, in accordance with subsection 38(e) of the *Transmission Regulation*, and approved the AESO's NID application.

AltaLink's Substation Alteration Application

The AUC found that requirements of Rule 007 and Rule 012 were met and that the substation alteration application was consistent with the need identified in the NID application. It also found that the potential environmental impacts of the substation alteration would be negligible and that there were no outstanding technical or other environmental concerns. The proposed substation alteration was determined to be in the public interest pursuant to section 17 of the *Alberta Utilities Commission Act* and the application was approved.

AltaLink Management Ltd. Application for Review and Variance of Decision 23848-D01-2020 2019-2021 General Tariff Application, AUC Decision 25769-D01-2020
Net Salvage Methodology

In this decision, the AUC granted a review application filed by AltaLink Management Ltd. ("AltaLink") requesting a review and variance of determinations made in Decision 23848-D01-2020 (the "Decision") denying a proposed change to AltaLink's net salvage methodology ("Net Salvage Proposal").

The AUC's authority to review its own decisions is discretionary and is found in Section 10 of the *Alberta Utilities Commission Act*. That act authorizes the AUC to make rules governing its review process and the AUC established Rule 016 under that authority. Rule 016 sets out the process for considering an application for review.

The review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the "preliminary question." If the review panel decides that there are grounds to review the decision, it moves to the second stage of the review process where the AUC holds a hearing or other proceeding to decide whether to confirm, vary, or rescind the original decision.

This decision addressed the preliminary question.

Hearing Panel Findings and Proceeding 25560

AltaLink, in Proceeding 23848, proposed to change its method for collecting net salvage costs related to the retirement of its utility assets. The majority hearing panel ("Hearing Panel") declined to approve the net salvage proposal, finding that AltaLink's proposed net salvage methodology, among other depreciation-related issues, could affect other parties and therefore, should be considered in an AUC initiated generic proceeding. The dissenting Hearing Panel member would have approved the net salvage proposal, and would not have instituted a generic proceeding.

The AUC initiated Proceeding 25560: Commission-Initiated Proceeding to Focus on Specific Depreciation-Related Matters, on May 14, 2020. The AUC closed the proceeding on July 8, 2020 stating, in part:

> 9. After reviewing the submissions from parties in the current proceeding, the Commission considers that there is no consensus that depreciation-related matters should be considered on a more generic basis. In particular, the regulated utilities maintained that intertemporal choice, intergenerational equity and depreciation-related matters including net salvage should be addressed on a case-by-case basis. This is consistent with the conclusions reached by the Commission in Bulletin 2016-16. In that bulletin, the Commission concluded that alternative approaches and rate treatments to mitigate or smooth the effect of rate or bill increases on consumers should be considered on a case-by-case basis, from time to time, in the context of comprehensive tariff applications.
>
> 10. Having considered all the submissions and the conclusions of the Commission in Bulletin 2016-16, the Commission has determined, on balance, that continuing with the current proceeding would not be an effective use of resources for the parties or for the Commission. The proceeding further appears unlikely to result in efficiency gains in considering the issues associated with depreciation and net salvage over the long run for all utilities.
>
> 11. In view of the above, the record for this proceeding is closed and this letter disposes of the current application. The Commission thanks parties for their submissions. (footnotes omitted)

View of the Parties

Views of AltaLink

AltaLink submitted that the majority Hearing Panel deferred its consideration of AltaLink's net salvage proposal in the Decision pending the outcome of a generic Proceeding 25560, which was to focus on depreciation-related matters. In AltaLink's view, no final decision regarding AltaLink's net salvage proposal was made. Proceeding 25560 was closed on the basis that alternative mechanisms for customer rate relief should be considered in utility-specific tariff proceedings, and not in generic proceedings. This required the AUC to complete the majority Hearing Panel's deferred determination regarding the proposed net salvage methodology for the 2019-2021 general tariff application period.

AltaLink argued that the closure of Proceeding 25560 constituted changed circumstances under sections 4(d)(iii) and 6(3) of Rule 016, that warrant a review and variance of the Decision. AltaLink submitted that the majority Hearing Panel deferred its determination of AltaLink's proposed net salvage methodology pending the outcome of the generic proceeding, and that the AUC's closure of Proceeding 25560 remits the majority Hearing Panel's deferred determination to the AUC. AltaLink was of the view, that the closure of Proceeding 25560 must lead the AUC to materially vary or rescind the majority Hearing Panel's findings.

Views of Interveners

The Utilities Consumer Advocate ("UCA") and the Industrial Power Consumers Association of Alberta ("IPCAA") shared AltaLink's view, that the net salvage proposal was never fully addressed in proceedings 23848 or 25560, and requested that the AUC address AltaLink's proposal.

Review Panel Findings

The Decision, which applied to the 2019-2021 test years, was issued on April 16, 2020. AltaLink's proposal under consideration by the Hearing Panel would reduce AltaLink's revenue requirement in the test period by as much as $88 million. This reduction could potentially result in immediate rate relief to current ratepayers.

The Review Panel directed a review of the majority Hearing Panel's findings concerning AltaLink's net salvage proposal.

Decision

Regarding the preliminary question, the Review Panel found there to be changed circumstances that could lead the AUC to materially vary or rescind the majority Hearing Panel's findings regarding the net salvage methodology.

The majority Hearing Panel's denial of the net salvage proposal resulted in the Hearing Panel making certain findings regarding AltaLink's updated net salvage percents. These findings are set out in Section 4.5.2 of the Decision. If the review panel varied or rescinded the majority Hearing Panel findings on the net salvage proposal, then the Hearing Panel's findings in Section 4.5.2 of the Decision may also be affected. Accordingly, depending on the review panel's findings regarding the net salvage proposal in the second stage of the review process, the findings in Section 4.5.2 of the Decision may also be varied or rescinded.

The AUC will issue process directions for the second stage of the review process in due course.

MÉTIS Corporation Métis Crossing Solar Project, **AUC Decision 25634-D01-2020**

Small Scale Generation Regulation

In this decision, the AUC approved the application from Metis Economic Trade and Industrial Services Corporation ("MÉTIS Corp.") to construct and operate a 4.86-megawatt ("MW") solar power plant designated as the Métis Crossing Solar Project ("the Project"), to qualify the power plant as a community generating unit, and to connect the power plant to the ATCO Electric Ltd. distribution system

Introduction

MÉTIS Corp. applied for approval to construct and operate a 4.86-MW solar power plant, and to connect the project to ATCO Electric's distribution system, pursuant to sections 11 and 18 of the *Hydro and Electric Energy Act*. Further MÉTIS Corp. applied for the project to be qualified as a community generating unit, as described in Section 3 of the *Small Scale Generation Regulation* ("*SSGR*").

Discussion

The project's renewable energy referral report provided by Alberta Environment and Parks ("AEP") stated that the project posed a low risk to wildlife and wildlife habitat.

A noise impact assessment form was submitted that indicated compliance with Rule 12: *Noise Control.* A participant involvement program was conducted in accordance with Rule 007: *Application for Power Plants, Substations, Transmission Lines, Industrial System Designation and Hydro Developments.* MÉTIS Corp. stated that there were no concerns raised by stakeholders.

In support of its application to have the project qualified as a community generating unit, in accordance with the *SSGR*, MÉTIS Corp. provided a community benefits statement describing the economic, environmental, and social benefits that the project would confer on the Métis Nation of Alberta. METIS Corp confirmed that the Project would be owned by MÉTIS Corp., which in turn is wholly owned by the Métis Nation of Alberta. MÉTIS Corp. stated that the Métis Nation of Alberta meets the definition of a community group under subsection 1(e)(vii) of the *SSGR*, as it is a society registered under the *Societies Act*.

ATCO Electric confirmed that, if the AUC approved the Project, it would cover the cost of metering for the Project.

Findings

The AUC considered these applications under sections 11 and 18 of the *Hydro and Electric Energy Act*, the *SSGR,* and section 17 of the *Alberta Utilities Commission Act.*

The AUC determined that an accurate estimate for the cost to purchase the meter, which is eligible for compensation under subsection 5(2)(a) of the *SSGR* was $35,302. The AUC was satisfied that as the distribution facility owner, ATCO Electric was entitled to recover the $35,302 incurred to purchase the meter for the Project pursuant to subsection 5(3)(a)(i) of the *SSGR*. Notwithstanding this determination, the AUC imposed the condition that MÉTIS Corp. must provide the AUC with written confirmation of the actual cost to purchase the meter. The confirmation was to be submitted within 30 days after the power plant was in service.

The AUC found that MÉTIS Corp. must comply with the requirements of Rule 033. Accordingly, the AUC made the approval conditional upon MÉTIS Corp.'s submission of a post-construction monitoring survey report to AEP and the AUC within 13 months of the Project becoming operational, and on or before the same date every subsequent year for which AEP requires surveys, pursuant to subsection 3(3) of Rule 033: *Post-Approval Monitoring Requirements for Wind and Solar Power Plants*.

The AUC approved the Project subject to the noted conditions.

***ATCO Pipelines 2019-2020 General Rate Application Second Compliance Filing,* AUC Decision 25789-D01-2020**

Rates - Deferral Accounts

In this decision, the AUC approved the application filed by ATCO Pipelines ("AP"), a division of ATCO Gas and Pipelines Ltd., requesting approval of its compliance filing to Decision 24817-D01-2020, which addressed AP's first compliance filing to Decision 23793-D01-2019, AP's 2019-2020 general rate application ("GRA"). The AUC approved the resulting revenue requirements for the years 2019 and 2020 as filed.

Introduction

In its application AP requested approval or confirmation of:

- The 2019 forecast revenue requirement of $275,552,000 and its 2020 forecast revenue requirement of $307,199,0003 as final;
- The finalization of all outstanding reserve and deferral account balances, along with the 2017-2018 Weld Assessment and Repair Program ("WARP") revenue requirement;
- The disposition of the information and technology ("IT") costs; and
- AP's compliance with directions given in Decision 24817-D01-2020.

Compliance with AUC Directions from Decision 24817-D01-2020

To comply with directions in Decision 24817-D01-2020, AP revised its 2019-2020 forecast revenue requirements as follows:

	2019	2020
Proceeding 24817 (first compliance filing)	$274,530,000	$304,730,000
Proceeding 25789 (second compliance filing)	$275,552,000	$307,199,000
Variance – increase in revenue requirement	$1,022,000	$2,469,000

Regarding directions related to the IT Common Matters decision, the AUC noted that AP's compliance and corresponding adjustments could have been more effectively presented, allowing for easier reconciliation of adjustments by the AUC. The AUC requested that, in future compliance filing applications, adjustments intended to address multiple directions not be combined within single line items. However, the AUC found that AP had properly applied adjustments to its IT rates and recalculated the 2015-2020 refund using its weighted average cost of capital as the interest rate applied to the carrying costs, resulting in a total refund of $4.02 million, as directed by the AUC.

Other Matters: 2019-2020 Revenue Requirement true-up and Deferral Accounts

AP proposed including its 2019-2020 revenue requirement true-up as a one-time adjustment to AP's monthly revenue requirement to NOVA Gas Transmissions Ltd. ("NGTL"). AP also proposed to settle all outstanding reserve and deferral account balances, including the 2017, 2018 WARP revenue requirement approved by the AUC in Decision 24176-D01-2020, as a one-time adjustment to AP's monthly revenue requirement to NGTL.

Findings

The AUC approved AP's calculations of the reserve and deferral account balances and found the settlement of these balances as a one-time adjustment to be reasonable and consistent with previous AUC decisions. The AUC approved AP's revenue requirement amounts of $275,552,000 for 2019 and $307,199,000 for 2020 on a final basis. The AUC also approved the one-time charge of $6,626,000 to be collected from NGTL.

***Market Surveillance Administrator Application to Make Public a Record that Identifies a Market Participant by Name*, AUC Decision 25809-D01-2020**

Market Surveillance Administrator - Release of Market Participant's Name

In this decision, the AUC approved the application made by the Market Surveillance Administrator ("MSA") under subsection 6(4)(b) of the *Market Surveillance Regulation* ("*MSR*") to make public a record that identifies a market participant by name.

Introduction

Pursuant to subsection 6(4)(c) of the *MSR,* the MSA must notify a market participant before publicly releasing a document that names the participant. Pursuant to subsection 6(5) of the *MSR*, the market participant can file an objection with the MSA within seven days of the notice.

The MSA reviewed the concerns in the market participant's objection to the release of the notice naming the participant. The MSA remained of the view that the release of the notice including the participant's name in a public document was within the MSA's mandate; enhanced fair, efficient and open competition in the market; and would not result in undue financial harm impacting the competitive position of the market participant. The MSA subsequently brought the application to the AUC pursuant to Subsection 6(7)(b) of the *MSR*. The MSA requested a private proceeding to review the reasonableness of the MSA's determination. The AUC determined subsections 6(2)(b), 6(4), 6(5), 6(7), 6(9) and 6(10) of the *MSR* to be relevant legislation. This legislation is relevant to the MSA's abilities to make public MSA investigations, market participants' ability to object to the publications, and the MSA's responsibility to review the objections.

Findings

Standard of Review is Reasonableness

Subsection 6(9) of the *MSR* specifically enables the AUC to act in the role of a reviewing body concerning the determination of the MSA and requires the AUC to assess the MSA's determination on the basis of reasonableness. The MSA has been recognized by the Court of Queen's Bench of Alberta as a body that possesses considerable expertise in carrying out its mandate. As such, it is entitled to deference. Consequently, the AUC considered whether the MSA's determination is transparent, intelligible, and justifiable, and as such falls within a range of possible, acceptable outcomes that are defensible in respect of the facts and law.

The principal issue before the AUC was whether it was reasonable for the MSA to determine that the factors it assessed under subsection 6(4) of the *MSR* favour the release of the name of the market participant in the public document it seeks to publish.

The MSA determined that the benefits of releasing the public document would include demonstration to the public that it was fulfilling its mandate, as well as control the messaging and public interest regarding the subject of its investigation of this market participant. In addition, the AUC found that the MSA's rejection of the market participant's claim that publishing the name in this circumstance could result in financial loss or harm to competitiveness was set out in the MSA's determination. The determinations were supported by past facts, which the AUC determined to be reasonably reliable, to support the MSA's conclusion that publishing the name would not reasonably result in this type of harm or loss.

The AUC also found that the MSA's reasoning that the *MSR* provides for a statutory scheme permitting the MSA to make public its activities in the fulfillment of its mandate, including the commencement and progress of its investigations, is supported by its analysis of the provisions set out in subsections 6(2), 6(3) and 6(4). The MSA's determination on the application of these provisions of the *MSR* to these documents was found to be reasonable.

The AUC accepted the MSA's determination that its investigative process is public and well known to market participants and that as such, the release of the name of the market participant will not diminish the procedural protections available to the market participant, nor necessarily result in a tarnished reputation. The AUC also accepted the MSA's reasoning that because the matters referenced in the public document are well known to market participants, the identity of the market participant would inevitably be known.

The AUC concluded that the determination made by the MSA was reasonable.

***BHE Canada Rattlesnake G.P. Inc, AltaLink Management Ltd. Rattlesnake Ridge Wind Power Project Facility Applications, Alberta Electric Systems Operator Needs Identification Document Application,* AUC Decision 25018-D01-2020**

Wind Power Plant Construction - Substation and Transmission Line Construction - Transmission System Access

In this decision, the AUC approved facility applications from BHE Canada Rattlesnake G.P. Inc. ("BHE") and AltaLink Management Ltd. ("AltaLink"). The AUC also confirmed the Alberta Electric Systems Operator's ("AESO") assessment of the need to be correct and approved its needs identification document ("NID") application to provide transmission system access to the wind power project.

Introduction

BHE filed applications 25018-A001 to 25018-A004, seeking approval to construct and operate a 117.6-megawatt ("MW") wind power plant, designated as the Rattlesnake Ridge Wind Power Plant. BHE further requested permits to construct and operate a collector substation, designated as the 719S Substation, and 50-meter-long Transmission Line, designated as Transmission Line 879AL. BHE also requested an order to connect the proposed power plant to AltaLink's existing 138-kV Transmission Line 879L.

The AESO filed application 25018-A005 seeking approval of the NID to provide transmission system access to the Rattlesnake Ridge Wind Power Project.

AltaLink filed applications 25018-A006 to 25018-A008 for approval to alter the existing Transmission Line 879AL to support the interconnection of the wind power project, and to construct a radio site with a telecommunications tower, designated as Rattlesnake Ridge 719R Radio Site, within the boundary of the proposed Rattlesnake Ridge 719S Substation.

The AUC considered the applications under sections 11,14,15,18 and 19 of the *Hydro and Electric Energy Act* ("*HEEA*") and section 34 of the *Electric Utilities Act* ("*EUA*"). In accordance with section 38(e) of the *Transmission Regulation*, the AUC noted that it must consider the AESO's assessment of the need to be correct unless an interested person satisfies the AUC that the assessment is technically deficient, or approval is not in the public interest.

Discussion

The Rattlesnake Ridge Wind Power Plant would consist of 28 Goldwind G155/4200 4.2-MW turbines with a hub height of 110 metres and a rotor diameter of 155 metres, and a 34.5-kV collector system of underground collector lines to connect the turbines to the Rattlesnake Ridge 719S Substation. Additionally, the Rattlesnake Ridge Wind Power Plant would include access roads, an operations and maintenance facility, and one meteorological tower.

BHE submitted a noise impact assessment ("NIA") that indicated the Rattlesnake Ridge Wind Power Plant and the Rattlesnake Ridge 719S Substation (collectively, the "Wind Power Project") would comply with Rule 012: *Noise Control.* BHE conducted a shadow flicker analysis that predicted that no receptor would experience shadow flicker in excess of 30 hours per year, with the most impacted receptor expected to experience up to 18 hours per year. It predicted that the Wind Power Project would have minimal potential for shadow flicker effects.

In response to concerns raised by parties regarding the risk of fire, BHE confirmed that it would complete an emergency response plan with the County of Forty Mile before the Wind Power Project became operational. In response to concerns raised by parties regarding impacts on rural roads, including maintenance of the roads, BHE stated it would develop a road use agreement with the County of Forty Mile.

In its NID application, the AESO indicated its preferred transmission facilities to meet the need identified included the addition of one 138-kV circuit, connecting the Wind Power Project to the existing 138-kV Transmission Line 879L. The NID application also included an alteration, addition or removal of equipment, including switchgear, and any operational, protection, control and telecommunication devices required to undertake the work as planned to ensure proper integration with the transmission system.

To meet the AESO's identified need, BHE requested approval to construct and operate the Transmission Line 879AL, which would connect the 719S Substation to the Alberta Interconnected Electric System ("AIES") via AltaLink's existing Transmission Line 879L. To meet the AESO's identified need, AltaLink requested approval to alter the existing Transmission Line 879L to support the interconnection of Transmission Line 879AL and install one 29-metre-tall telecommunications tower at the proposed Rattlesnake Ridge 719S Substation, the Rattlesnake Ridge 719R Radio Site. AltaLink and BHE applied to connect the Wind Power Project via Transmission Line 879AL to Transmission Line 879L.

Following participant involvement programs, BHE noted that there were outstanding concerns from local landowners in the area.

Environmental Impacts

BHE retained Golder to prepare an environmental evaluation for the Wind Power Project and Transmission Line 879AL, which determined that the potential effects on the environment would not be significant.

BHE submitted a renewable energy referral report issued by Alberta Environment and Parks (“AEP”) Wildlife Management. Based on the Wind Power Project’s siting, limited wildlife use in the area, and the monitoring and mitigation commitments made by BHE, AEP determined that the Wind Power Project posed an overall moderate risk to wildlife and wildlife habitat.

AEP determined that the Wind Power Project’s bat mortality risk during operation would be high based on the extremely high bat activity recorded in the survey results from the wind power project area. AEP noted that BHE committed to implementing the required mitigations to reduce the overall risk of bat mortality to acceptable levels; however, AEP acknowledged that extreme mitigations may be required depending on the results of the post-construction monitoring to reduce the mortality rate to acceptable levels.

Findings

The AUC found that the noise impacts associated with the Wind Power Project were mitigated to an acceptable degree and that shadow flicker effects will be minimal. The AUC further acknowledged BHE’s commitments regarding the development of a road use agreement and the development of an emergency response plan in consultation with the County of Forty Mile.

Environmental Impacts

The AUC acknowledged that the Wind Power Project and Transmission Line 879AL would be located to avoid native habitat and wetlands. The AUC was satisfied that BHE’s post-construction monitoring plan would adequately address potential environmental impacts of the wind power project and was aligned with post-construction wildlife requirements set out in the *Wildlife Directive for Alberta Wind Energy Projects* and in the referral report.

BHE acknowledged the high level of bat activity in the Wind Power Project area and the identified risk to migratory bats from the operation of the wind power project and expressed its willingness to implement mitigation beyond those outlined by AEP in the referral report to address the risk to bats.

To ensure compliance with Rule 033: *Post-Approval Monitoring Requirements for Wind and Solar Power Plants,* as a condition of the approval of the Rattlesnake Ridge Wind Power Plant, the AUC directed BHE to submit an annual post-construction monitoring survey report to AEP and the AUC within 13 months of the Rattlesnake Ridge Wind Power Plant becoming operational, and on or before the same date every subsequent year.

The AUC was satisfied that with the application of BHE’s mitigation measures, post-construction monitoring, and implementation of any additional mitigation measures as directed by AEP, the potential environmental effects from the Wind Power Project facilities can be adequately mitigated. The AUC also found that approval of the preferred substation location is in the public interest in that it better mitigates the impacts to the affected landowners.

Conclusion

Subject to the imposed condition, the AUC considered the Rattlesnake Ridge Wind Power Plant to be in the public interest in accordance with section 17 of the *Alberta Utilities Commission Act*.

The AUC approved the AESO’s NID application, and found that the application from BHE and AltaLink for Transmission Line 879AL and Transmission Line 879L addressed the need identified by the AESO. The AUC found that BHE and AltaLink’s asset transfer agreement for Transmission Line 879AL met the requirements of section 24.31 of the *Transmission Regulation* and expected BHE and AltaLink to file an ownership transfer application, and a letter of enquiry to amend the connection order, at the earliest opportunity after energization of the Wind Power Project.

Direct Energy 2020 Default Rate Tariff and Regulated Rate Tariff Interim Rates Application, AUC Decision 25727-D01-2020

Revenue Deficiency - Potential Rate Shock

In this decision, the AUC approved the application from Direct Energy Regulated Services ("DERS") to adjust its 2020 interim rates for its default rate tariff ("DRT") and regulated rate tariff ("RRT").

Particulars of the Application

As part of its application, DERS requested approval of the DRT non-energy rates, the DRT return margin charge, the DRT charge for certain energy costs, the DRT monthly charge for labour related to gas procurement, and RRT non-energy related rates.

The DRT and RRT non-energy rates were applied on a per-site per day basis. The DRT return margin charge, the DRT charge for certain energy costs, and the DRT monthly charge for labour related to gas procurement were all included as part of DERS' monthly gas cost flow-through rate, which was applied on a per gigajoule ("GJ") basis.

In its application, DERS requested the approval of the 2019 final rates and charges approved in Decision 25255-D01-2020 as the updated interim rates for 2020, effective September 1, 2020. DERS requested these updated interim rates "in order to minimize, to the extent possible, the rider that DERS expected would be required to true-up 2020 rates." It further requested that these updated interim rates be in effect until final rates are approved for DERS in its upcoming 2020-2022 DRT and RRT application.

Findings

Based on the timing associated with processing the application, the AUC addressed DERS' request based on revising interim rates effective October 1, 2020. The analysis provided by DERS in support of the application was calculated on an implementation date of September 1, 2020, and the AUC considered that the analysis would not materially change if it was based on an implementation date of October 1, 2020.

The AUC acknowledged DERS' submission that the conservative revenue deficiency for 2020 would likely be greater than the previously estimated $9.3 million, once the impacts resulting from the COVID-19 global pandemic are fully known. The AUC found that the revenue deficiency is probable, based on the expected decrease in site numbers and gas consumption numbers between 2019 actuals and the 2020 estimates, as provided by DERS.

Based on DERS' statement that the 2020 estimates were based on the forecast assumptions approved by the AUC in approving the final 2019 DRT and RRT revenue requirements, the AUC was satisfied that no material contentious items needed to be excluded.

The AUC considered that claims of financial hardship or inability to continue to provide safe utility operations were not applicable in this case.

The AUC found that allowing DERS to recover a portion of the conservatively estimated revenue deficiency, to help ease potential rate shock for 2020, is an acceptable balance to help alleviate what could be a significant revenue deficiency for 2020, especially when the final impact of the COVID-19 pandemic on DERS' 2020 costs was unknown.

The AUC considered that while the main purpose of the interim rate increase is not to send a price signal to customers, the requested interim rate increase does send a message to customers that the cost of being a DRT and RRT customer of DERS is expected to increase in 2020. The AUC considered that this price signal should be made known to customers, in order to allow customers to make informed choices about their electricity and gas providers.

The AUC considered it inappropriate to apply the DRT and RRT non-energy charge interim rate increases on an across-the-board basis in this case, because DERS had separate rate classes with differing site numbers.

Consequently, these various rate classes were assigned different percentages of the revenue requirements, which in turn resulted in different non-energy rates.

The AUC approved the updated DRT and RRT interim rates/charges as requested by DERS effective October 1, 2020. The interim rates/charges will be in place until 2021 and beyond until they are replaced by final rates for the applicable year, or until such time as the AUC approves updated interim rates/charges.

AltaGas Utilities Inc. 2020-2021 Unaccounted-For Gas Rider E and H, AUC Decision 25747-D01-2020

Audit of Problem Areas - Compliance with Decision 24763-D01-2019

In this decision, the AUC approved AltaGas Utilities Inc.'s ("AltaGas") application to recover amounts associated with unaccounted-for gas ("UFG") rate riders E and H.

Introduction

AltaGas rate riders E recovers the amount of UFG associated with producer transportation service and Rider H recovers the amount of UFG associated with Natural Gas Settlement System ("NGSS") processes. AltaGas proposed decreasing Rider E from 1.10 percent to 0.98 percent, and decreasing Rider H from 1.11 percent to 0.99 percent. Rider E and Rider H are designed to recover amounts associated with UFG.

In past UFG decisions, most recently in Decision 24763-D01-2019, the AUC stated that while not all causes of UFG can be eliminated, it expected the percentages to decrease over time as a result of AltaGas's initiatives to reduce UFG. The AUC directed AltaGas to quantify the causes of UFG, to provide reasons for any increases or decreases in UFG, to continue to take action to reduce UFG fluctuations and UFG amounts overall, and to provide historical monthly data for the receipt and delivery volumes and UFG percentage losses or gains and a regional UFG breakdown.

Compliance with Previous AUC Directions

In its application, AltaGas provided information regarding monthly data for the period of June 2010 to May 2020, UFG by region, and the most significant causes of UFG on its system, in compliance with the direction in Decision 24763-D01-2019. It further included a description of actions taken to reduce UFG and UFG fluctuations, which included ongoing review and monitoring, AltaGas's system betterment program, meter testing, the retirement and replacement of assets known to contribute to UFG, continual support of damage prevention efforts, and continual improvement of processes that identify and reduce UFG.

AltaGas provided UFG data separated into north, central, and south regions from June 2019 to May 2020. AltaGas stated there were 128 pipeline incidents in the Barrhead/Westlock/Morinville ("BWM") area of the north region during the first half of the 2019-2020 reporting period. The full 2018-2019 reporting period showed 80 incidents in the same area. As leaks were identified and repaired earlier in the reporting period, the leaks occurred for shorter periods and contributed to the reduction of overall gas lost from the system compared to the prior year.

The most significant contributors to a reduction in UFG in the north region were the identification and reparation of many of the leaks early in the reporting period and the absence of high-pressure leaks. AltaGas attributed the moderate increase in UFG in the central region between the 2018-2019 and 2019-2020 periods to the normal year-to-year fluctuations in UFG.

AltaGas's south region showed a net UFG gain, consistent with the last three years. AltaGas had conducted multiple investigations and efforts yielding no substantial explanation of the variance.

In 2020, AltaGas advised it would conduct an in-depth physical audit of the problem areas. This will include a thorough physical examination of a large sample of receipt and delivery sites in the area.

Findings

The AUC was satisfied that the calculations of rate Rider E and rate Rider H were accurate and consistent with the methodology approved in previous decisions. The AUC was satisfied that the proposed rate riders fall within the historical range of UFG percentages. The AUC noted its expectation that UFG fluctuations and overall UFG percentages should decrease over time as a result of AltaGas's ongoing initiatives and expenditures to reduce UFG. It further noted its expectation that AltaGas would, over time, improve its ability to identify and quantify the causes of UFG.

AltaGas was directed to provide the data and results of the audit of the UFG problem areas in the south region in its 2021-2022 UFG application to be submitted no later than July 30, 2021. The AUC was satisfied that AltaGas' proposed adjustments to Rider E and Rider H were reasonable and approved the application.

Milner Power Inc., ATCO Power Ltd. Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology, AUC Decision 790-D08-2020
Loss Factor Calculation

In this decision, the AUC found that the Alberta Electric System Operator's ("AESO") amended Module C payment plan compliance filing ("Module C Payment Plan") concerning the collection and reimbursement of loss charges calculated for the period from January 1, 2006, to December 31, 2016, (the "Historical Period") is compliant with directions in Decision 790-D06-20172 and Decision 25150-D02-2020.

Background

This decision followed a series of decisions issued by the AUC and its predecessor, the Alberta Energy and Utilities Board, concerning a complaint by Milner Power Inc. in 2005, that the methodology used to calculate line losses did not comply with Alberta's *Transmission Regulation*. An explanation of line losses and the full chronology of this proceeding can be found in previous decisions.

In Decision 790-D06-2017, the AUC approved a methodology for the calculation of loss factors for the historical period and directed the AESO to submit a compliance filing implementing the methodology for that period.

In Decision 790-D07-2019, the AUC approved a request from the AESO to bifurcate the compliance filing directed in 790-D06-2017. In doing so, the AUC deferred its consideration of issues related to the collection and reimbursement of loss charges until they were addressed by the AESO in its second compliance filing.

In Decision 25150-D02-2020, the AESO was directed to settle line losses for the historical period over three settlement periods; one three-year and two four-year periods. The AESO was also directed to assign the necessary resources to implement this settlement approach and to recover its incremental costs through the energy market fee.

Current Application

On July 28, 2020, the AESO submitted its Module C Payment Plan.

Heartland Generation Ltd. ("Heartland") responded to the AUC's process letter. In its submission, Heartland noted the AUC statement in Decision 25150-D02-2020, that settlement of the first three years of historical loss factors should occur as soon as possible. Relying on this statement, Heartland supported a limited scope and strict process schedule for this compliance proceeding.

Milner Power Inc. ("Milner") submitted that it supported the AESO's filings, but raised concerns regarding the application of the 60-day due-date delay, and possible settlement delay if the AUC was unable to issue a decision before September 30, 2020. Following the response from the AESO, stating the use of the phrase "at least 60 days" was to accommodate potential variability in financial settlement dates and would not result in excessive delays, Milner stated its support of the AESO's filing.

Collection and Reimbursement Requirements in Decision 790-D06-2017 and 25150-D02-2020

Entity to Receive Invoices

Decision 790-D06-2017 directed the AESO to issue invoices to the supply transmission service ("STS") contract holder at the time the losses originally occurred. The AESO's Module C Payment Plan defines "Eligible Entity" as "a current or former market participant who has been issued invoices by the AESO for line loss charges in accordance with AUC Decisions 790-D06-2017 and 25150-D02-2020." The AUC found the AESO's proposed definition of "Eligible Entity" to comply with the direction in paragraph 208(c) of Decision 790-D06-2017.

Three Settlement Periods

In Decision 25150-D02-2020, the AESO was directed to implement three settlement periods including one of three years, and two of four years each for the historical period with simultaneous collection and reimbursement pursuant to the ISO tariff. The AUC found the settlement periods proposed by the AESO in the Module C Payment Plan to comply by this direction.

Accelerated Approach

The AESO was direct to implement the accelerated single settlement approach and recover the incremental cost through the energy market trading fee. The AUC found that the information provided by the AESO demonstrates its use of an accelerated approach to settle the line loss charges in accordance with the three settlement periods stipulated in Decision 25150-D02-2020. As the deployment of the necessary resources to implement the three settlement periods was ongoing, the AUC expected that the AESO would continue to comply with this direction until the calculations are completed and all relevant line loss charges are settled.

Statements of Account

The AESO was directed to provide statements of account for the final line loss charges to market participants setting out the recalculated line loss charges for the historical period on a year by year basis as they become available, before a final true-up takes place.

The AESO stated that it would issue preliminary and final settlement statements based on the schedule included in the Module C Payment Plan. The AUC found that the timing for statements setting out the recalculated line loss charges for the historical period proposed in the AESO's Module C Payment Plan complies with the AUC direction in Decision 790-D06-2017.

Interest

The AESO was ordered in Decision 790-D06-2017, to charge/award interest, equal to the Bank of Canada rate plus one and one half percent. The AESO was required to set out the interest attributed to the monthly amounts for each market participant as it calculated and made available the updated statements of account for the final line loss charges.

As this was an ongoing requirement, the AUC expected that the AESO would continue to comply with this direction until all loss factor charges are settled for the historical period.

Structure, Terms, and Eligibility Criteria

The AESO was directed to develop the structure, terms, and eligibility criteria for its proposed payment plan and file it with the compliance filing to Decision 790-D06-2017. That AUC found criteria proposed in the Module C Payment Plan complies with the direction in Decision 790-D06-2017.

Recovery of Costs Through the Energy Market Trading Fee

The AUC direction concerning the recovery of costs through the energy market trading fee remained outstanding, as it would be applied as the line loss calculations were completed and the costs associated with completing the settlement became known. The AUC considered these to be the AESO's own administrative costs as defined in section 1(1)(g) of the *Transmission Regulation*, which are defined to include the transmission-related costs and expenses of the AESO respecting the administration, operation and management of the AESO.

Collection of the Shortfalls Through Rider E

The AUC direction concerning the collection of any shortfalls through Rider E remained outstanding and could be required once all calculations were completed and any shortfalls became known. In the event of shortfalls, the AUC expected the AESO to include them in a Rider E as part of its ongoing tariff filings before the AUC.

Alberta Electric System Operator Approval of Proposed Amended ISO Rules and Consolidated Authoritative Document Glossary Terms and Conditions, AUC Decision 25688-D01-2020
Administrative Changes

In this decision, the AUC approved changes to the Independent System Operator ("ISO") rules and Alberta Electric System Operator ("AESO") Consolidated Authoritative Document Glossary ("CADG") terms and conditions (collectively the "Administrative Changes") proposed by the AESO.

<u>Introduction</u>

Suncor Energy Inc. submitted a statement of intent to participate ("SIP") expressing its view that the omission of the older consultation record rendered the AESO's application incomplete and out of compliance with AUC Rule 017: *Procedure and Process for Development of ISO Rules and Filing ISO Rules with the Alberta Utilities Commission.* The AUC issued a ruling denying the request for the inclusion of the older consultation record.

<u>Legislative and Regulatory Framework</u>

Section 20.9 of the *Electric Utilities Act* ("*EUA*") requires the AUC to make rules requiring the AESO to consult with parties in the development of ISO rules and permits the AUC to develop rules governing the AESO's process in the development of those rules. AUC Rule 017 was created in response to Section 20.9 of the *EUA.*

<u>Background</u>

The proposed administrative updates contain Administrative Changes, reflecting requirements and clarifications related to the energy-only market, ensuring alignment with other ISO rules and definitions, removing obsolete requirements, and aligning defined terms with the amendments to applicable defined terms in the *EUA.*

<u>Findings</u>

The AUC was satisfied that the application met the requirements of Section 20.21(2) of the *EUA* and that the AESO complied with the requirements set out in Rule 017. Accordingly, the AUC approved the proposed administrative updates to the following ISO Rules and CADG terms and conditions.

ISO Rule	**Name and Description**	**Proposed Action**
Section 103.2	*Dispute Resolution*	Amend
Section 201.1	*Pool Participant Registration*	Amend
Section 201.4	*Submission Methods and Coordination of Submissions*	Amend
Section 203.4	*Delivery Requirements for Energy*	Amend

Section 304.2	*Electric Motor Start Requirements*	Amend
Section 304.8	*Event Analysis*	Amend
Section 305.4	*System Security*	Amend
Section 306.3	*Load Planned Outage Reporting*	Amend
Section 306.4	*Transmission Planned Outage Reporting and Coordination*	Amend
Section 306.5	*Generation Outage Reporting and Coordination*	Amend
Section 501.10	*Transmission Loss Factors*	Amend
Section 502.9	*Synchrophasor Measurement Unit Technical Requirements*	Amend
Section 507.1	*Open Access Requirements for Proposed Interties*	Amend
AESO CADG	“agent” definition	Amend
AESO CADG	“Alberta internal load” definition	Amend
AESO CADG	“business day” definition	Amend
AESO CADG	“generating asset steady state” definition	Amend
AESO CADG	“LTA metrics” term and definition	Remove
AESO CADG	“LTA threshold” term and definition	Remove
AESO CADG	“LTA threshold actions” term and definition	Remove
AESO CADG	“market participant” definition	Amend
AESO CADG	“point of supply” definition	Amend
AESO CADG	“ramping” definition	Amend
AESO CADG	“system access service” definition	Amend

***Community Generation Working Group and FortisAlberta Inc. Decision on Preliminary Question Application for Review of Decision 22942-D02-2019 Alberta Electric System Operator 2018 Independent System Operator Tariff,* AUC Decision 25101-D01-2020, 25102-D01-2020**
Review and Variance - Distributed Generation - AESO Tariff

In this decision, the AUC approved the preliminary stage application from the Community Generation Working Group (“CGWG”) and FortisAlberta Inc. (“FortisAB”) for review and variance of specific findings in section 7.3 of Decision 22942-D02-2019 (the “Decision”) regarding the Alberta Electric System Operator’s (“AESO”) proposed adjusted metering practice. Having granted a review of the AESO’s proposed adjusted metering process, the AUC would proceed with a second stage variance proceeding.

<u>Introduction and Background</u>

The Decision addressed an application from the AESO for approval of an adjusted metering practice as part of its 2018 ISO tariff application. In the Decision, the hearing panel (“Hearing Panel”) approved the AESO’s proposed adjusted metering. Under the approved adjusted metering practice the AESO would separately meter supply transmission service (“STS”) and distribution transmission service (“DTS”) amounts at distribution facility owners (“DFO”) substations on a “gross” basis rather than metering energy flowing on the Alberta Interconnected System (“AIES”) on a “net” basis. Among other effects, the Decision to allow the AESO to meter on a gross basis could have a significant effect on the economics of distribution-connected generation, because it would cause AESO contribution amounts to include amounts arising from the substation faction formula in accordance with the ISO tariff.

The AUC's Review Process

The AUC's authority to review its own decisions is discretionary and is found in Section 10 of the *Alberta Utilities Commission Act*. That act authorizes the AUC to make rules governing its review process and the AUC established Rule 016 under that authority. Rule 016 sets out the process for considering an application for review.

The review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the "preliminary question." If the review panel decides that there are grounds to review the decision, it moves to the second stage of the review process where the Commission holds a hearing or other proceeding to decide whether to confirm, vary, or rescind the original decision.

In this decision, the review panel ("Review Panel") decided the preliminary question.

Grounds for Review and Hearing Panel Findings

CGWG Review Application

In the review application, the CGWG requested a review of the AUC's approval of the AESO's transmission cost allocation substation fraction formula methodology. The CGWG objected primarily to paragraph 742 of the Decision:

> 742. The substation fraction formula is a long-established mechanism used by the AESO to allocate the costs of local interconnection facilities that may have joint use. Further, while the Commission considers that use of a ratio of the respective STS and DTS contract capacities as a percentage of the combined DTS and STS contract capacities of customers using the local interconnection facilities is a relatively simple mechanism, it is not unreasonable in the absence of any other information. The Commission notes that no parties in the current proceeding have provided any evidence suggesting that a mechanism other than the substation fraction formula would be an improvement for this purpose.

To support its review request, the CGWG argued two grounds of review: (1) errors of fact, law, or jurisdiction, which are apparent in the Decision or had been established to exist on a balance of probabilities; and (2) previously unavailable facts material to the particular aspect of the Decision that is the subject of this application, that existed prior to the issuance of the Decision but were not previously placed in evidence or identified in the proceeding, and could not reasonably have been discovered during the course of the 2018 ISO Tariff proceeding.

The CGWG argued the substation fraction formula proposed by the AESO was not a "long-established mechanism" and that there were other options available to the AUC that were outlined in evidence. It further argued that formula changes embedded in AESO ID# 2019-016T could not have been discovered at the time of proceeding 22942 by the CGWG exercising reasonable diligence.

FortisAlberta Review Application

In its review application, FortisAB sought a review of the findings on the AESO's adjusted metering practice. In support of its application, FortisAB argued that there were multiple errors in law and fact in the Decision and that, since the issuance of the Decision, there had been changes in circumstances material to the Decision.

Review Panel Findings

The Review Panel made no findings in response to the specific grounds raised by each of the CGWG and FortisAlberta in their respective review applications. Because the Review Panel has directed a review of the Hearing Panel's findings in section 7.3 of the Decision, including consideration of a new proposal for the substation fraction methodology that could resolve issues raised by these parties, a determination of whether the grounds raised by these parties has been demonstrated and further, whether the errors alleged by each of these parties are both obvious on the face of the Decision and material, was not required.

Decision

In answering the preliminary question, the Review Panel found that there were changed circumstances that could lead the AUC to materially vary or rescind its findings in section 7.3 of the Decision. It also noted that there were specific findings in section 7.3 of the Decision which would not be the subject of a variance proceeding, and it outlined these findings in an appendix to the decision. Having met the first stage of the review and variance application, the AUC advised that it would issue process and scope directions for a new proceeding to consider the second stage of the review process, the variance proceeding, in Proceeding 25175: 2018 ISO Tariff Compliance Filing Pursuant to Decision 22942-D02-2019 and 2020 ISO Tariff Update Application.

CANADA ENERGY REGULATOR

***Application by West Coast Olefins Ltd. Regarding Jurisdiction over the Enbridge Frontier Project,* CER Letter Decision A7I4V6**

Westcoast Test - Jurisdictional Determination

In this decision, the CER denied the application by West Coast Olefins Ltd. ("WCOL") to establish a process to decide whether the Enbridge Frontier Project ("Project"), proposed by Enbridge Frontier Inc. ("Enbridge Frontier"), should be under federal jurisdiction.

WCOL Submissions

WCOL noted that the CER has the jurisdiction to determine the Project's proper jurisdiction by virtue of subsection 32(1) of the *Canadian Energy Regulator* Act ("*CER Act*"). It asked the CER to follow the National Energy Board's ("NEB") practice of having a two-step process for determining jurisdiction whereby the CER would apply the *prima facie* test to decide whether holding a full jurisdictional process is warranted. WCOL submitted that, according to the *Westcoast* test, as established by the Supreme Court of Canada in *Westcoast Energy Inc. v Canada (National Energy Board)*, [1998] 1 SCR 322 (*"Westcoast*"), a work or undertaking entirely within one province is under federal jurisdiction if it is, in relation to another federal work or undertaking:

- functionally integrated and subject to common management, control and direction; or
- essential, vital and integral to the other work or undertaking.

Based on filings by Enbridge Frontier, WCOL described the Project proposal as including a new straddle plant that would extract natural gas liquids ("NGLs) from gas from the BC Pipeline, and return the resulting gas back to the BC Pipeline near Chetwynd, BC. WCOL stated that the Project as well as the BC Pipeline were both ultimately owned by Enbridge Inc., and that the Project would be physically connected to the BC Pipeline. WCOL also pointed to questions it had raised regarding the goal for the NGLs transported by the Project, pointing to what were, in its view, "indicators of interprovincial aspects". WCOL submitted that the CER should make inquiries to Enbridge Frontier to determine jurisdiction.

Enbridge Frontier

Enbridge Frontier did not dispute the CER's jurisdiction to decide whether to hold a process to decide the jurisdictional question with respect to the Project. Enbridge Frontier said that WCOL had not met the *prima facie* test that the Project was part of a federal undertaking and that, as a result, the CER should decline to establish such a process.

Applying the first branch of the *Westcoast* test, upon which WCOL relied, Enbridge Frontier said that the Project was a local undertaking, providing service solely within BC, by extracting NGLs from existing systems in BC and transporting them to market in BC. Enbridge Frontier submitted that other than the Project's physical connection to the BC Pipeline, the points raised by WCOL offered no indication whatsoever of functional integration between the Project and the BC Pipeline. Enbridge Frontier further submitted that importantly, there was no connection from the Project to any federally regulated transport system to transport NGLs out of BC. Enbridge Frontier pointed out that the Project's purpose is to extract and transport NGLs within BC.

Enbridge Frontier further submitted that the Project's purpose to extract and transport NGLs within BC is separate from the BC Pipeline (which transports gas from Alberta and BC to downstream markets in BC and the United States) and that the Project does not include any interprovincial infrastructure. Enbridge Frontier stated that impacts of local projects on federal undertakings do not turn local projects into federal undertakings, and that the Project's downstream impacts on the BC Pipeline are not relevant to the jurisdictional question.

Reply from WCOL

WCOL summed up its reply and argument about functional integration as being met on a *prima facie* basis, by the Project's connection to and sourcing NGLs from the BC Pipeline, and because the Project is "positioned to export NGLs out of province".

CER Decision

Legal Tests for Initiating Full Jurisdictional Process

As noted by both WCOL and Enbridge Frontier, the test for whether a work or undertaking located entirely within one province is subject to federal regulation was outlined by the Supreme Court of Canada in the *Westcoast* decision. According to *Westcoast*, a work such as a pipeline located entirely within one province can fall into federal jurisdiction if it is part of a federal work or undertaking in the sense of being functionally integrated and subject to common management, control, and direction, or if it is vital and integral to a federal work or undertaking.

The CER only considered the first of these possibilities, as it is the one WCOL solely relied on. With respect to functional integrity, the CER determined key considerations to include whether:

- the proposed project shared a common purpose with a federal work or undertaking (in this case, the BC Pipeline);
- the owner of the project had a commercial relationship with a federal work or undertaking;
- the two undertakings are dedicated to each other, such that the goods or services provided by one operation are for the sole benefit of the other's operation and/or its customers, or are they generally available;
- the undertakings were interdependent on each other;
- they operate in common as a single enterprise; and
- the proposed project is physically connected to a federal work or undertaking.

Regarding common management, control and direction, the considerations focus on daily operations of the facilities.

In its decision not to hold a full process to make a jurisdictional determination, the CER applied the *Westcoast* test on a *prima facie* basis. According to *Sawyer v TransCanada Pipeline Limited*, 2017 FCA 159 ("*Sawyer*"), a tribunal applying a *prima facie* test must ask only whether there is an arguable case, and must do so without weighing and balancing evidence or considering the merits of the case.

Applying the Test to the Frontier Project

The CER noted that there is no dispute that the Project would connect to the interprovincial, federally regulated, BC Pipeline, and that Enbridge Frontier (the Project's proponent and owner) and WEI (BC Pipeline's owner) have a relationship as companies wholly owned by a common corporate parent, Enbridge Inc.

However, the CER found no evidence supporting WCOL's speculation that the Project was interprovincial in nature. The CER was unable to make a *prima facie* finding that the Project and BC Pipeline share a common purpose. The CER found that the Project, as proposed, does not make the Project and the BC Pipeline interdependent any more than other tie-ins that connect to and remove gas from the BC Pipeline. The CER was unable to make a *prima facie* finding that the Project and the BC Pipeline are interdependent, or that they operate solely for each other's benefit.

The CER found that WCOL succeeded in demonstrating a *prima facie* or arguable case of common management, control and direction between the Project and the BC Pipeline, but WCOL failed with respect to functional integration. The CER declined to initiate a process, under subsection 32(1) of the *CER Act*, to determine whether the Project would be subject to federal jurisdiction.

WCOL further requested the CER look at impacts of potential downstream compression requirements along the B Pipeline's T-South system and the potential cost impacts. WCOL argued that the removal of NGLs may lower the hydrocarbon dewpoint on the T-South system and requested the CER look at any related safety issues. The CER found these allegations vague and not warranting further inquiry.