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 the legislative scheme and 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

***New Direction for Coal Activity in the Eastern Slopes of Alberta's Rocky Mountains,* AER Bulletin 2022-04**
Coal Development - Approval Suspension

On March 4, 2022, the Government of Alberta released a report from a coal policy committee it formed in early 2021 to gather feedback on future policy related to coal development in Alberta. Ministerial Order 002/2022 (the "*Order*") was issued in response to the report.

Under the *Order*, the AER was directed to continue its suspension of all approvals and not accept any new applications for coal exploration activities on Category 2, 3, and 4 lands. The *Ord*er did not require suspension of coal exploration and development applications on Category 3 and 4 lands related to an advanced coal project or an active approval for a coal mine. The *Order* defines "advanced coal projects" and "active approvals for coal mines" as follows:

- advanced coal project: Proposed coal projects where applicants have submitted a project summary to the AER to determine whether a proposed project requires an environmental impact assessment; and

- active approval for a coal mine: Existing coal projects granted a licence to operate under the *Coal Conservation Act*.

This means that advanced coal projects will continue to be reviewed by the AER to ensure any proposed exploration or development is safe, environmentally responsible, meets all requirements, and that active coal mines can continue to operate on Category 3 and 4 lands within all AER requirements.

The directions will remain in place until either the Minister of Energy or the Minister of Environment and Parks gives written notice.

The *Order* does not restrict abandonment and reclamation, security, or safety activities on Category 2, 3, and 4 lands. Operators are permitted to proceed with abandonment and reclamation activities and to enter these sites to:

(a) monitor and ensure the site is left in a state that is safe to the environment, wildlife and public; and

(b) perform routine checks and maintenance at the site to ensure all property and equipment is secure from wildlife access, vandalism, and weather events.

***New Edition of Directive 017,* AER Bulletin 2022-05**
Oil Sands - Well Testing

On March 17, 2022, the AER released a new edition of Directive 017: *Measurement Requirements for Oil and Gas Operations*.

S. 12.3.9 contains well testing requirements for thermal *in situ* oil sands operations. These requirements have been modified. A program for testing each operating production well must be implemented and described in the project's measurement, accounting, and reporting plan. The requirement to have one valid testing hour for every forty hours of operation was removed.

The measurement, accounting, and reporting plan is described and required by Directive 042: *Measurement, Accounting, and Reporting Plan ("MARP") Requirements for Thermal Bitumen Schemes*:

(a) Existing MARPs should be updated immediately and must be available for review when requested by the AER; and

(b) Applications for new MARPs must meet these new Directive 017 requirements.

This change enables the collection of more representative well-level production data. It provides operators with additional flexibility in conducting their well testing programs while maintaining compliance with the existing proration factors specified in s. 12.3.10 of Directive 017.

***New Edition of Directive 050,* AER Bulletin 2022-06**
Drilling Waste - Regulatory Efficiency

On March 28, 2022, the AER released a new edition of *Directive 050: Drilling Waste Management*. To contribute to the Government of Alberta's *Red Tape Reduction Act*, the AER streamlined the directive to remove duplicate requirements.

The changes clarify the regulatory and operational requirements, improve regulatory application efficiency, and enable operators to reduce land disturbance from drilling waste management practices.

***New Editions of Directives 055 and 058 and Rescinded Documents,* AER Bulletin 2022-07**
Water Storage - Regulatory Efficiency

On March 28, 2022, the AER released new editions of *Directive 055: Storage Requirements for the Upstream Petroleum Industry* and *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry.*

The AER updated the directives to incorporate the storage of large volumes of water such as produced water, water-based flow back, and oilfield landfill leachate in storage devices for reuse in hydraulic fracturing. The AER also revised the directives to improve clarity and remove redundant and outdated requirements.

Directive 055 was updated to include technical requirements for engineered containment ponds and bladders with structural frames and expanded requirements for above-ground synthetically lined walled storage systems. *Directive 058* was updated to include water storage for reuse in hydraulic fracturing as a waste storage activity. The AER changed s. 8.030(2) of the *Oil and Gas Conservation Rules* to clarify that any storage device or system must follow the requirements in *Directive 055*.

The AER consolidated several ancillary documents into the directives, and as a result, the following documents were consequently rescinded:

- Previous editions of Directive 055, Directive 058, and their addenda;
- Interim Directive ("ID") 99-04: *Deposition of Oilfield Waste into Landfills*;
- ID 2000-04: *An Update to the Requirements for the Appropriate Management of Oilfield Wastes*;
- Informational Letter ("IL") 98-01: *A Memorandum of Understanding Between Alberta Environmental Protection and the Alberta Energy and Utilities Board Regarding Coordination of Release Notification Requirements and Subsequent Regulatory Response*;
- IL 98-02: *Suspension, Abandonment, Decontamination, and Surface Land Reclamation of Upstream Oil and Gas Facilities*; and
- Updates to Storage Requirements for the Upstream Petroleum Industry Discussion Document on Directive 055 July 2009.

ID 2000-03: Harmonization of Waste Management and Memorandum of Understanding Between the Alberta Energy and Utilities Board and Alberta Environment has been discontinued as an interim directive, but it will be continued as a memorandum of understanding because it informs the relationship between the AER and Alberta Environment and Parks on waste management.

Over the next few months, administrative changes will be made to several directives and manuals to reflect the document rescissions and changes to *Directive 055* and *058*. No requirements in these associated directives will be changed.

Applying for Temporary Diversion Licences, **AER Bulletin 2022-08**
Water Act - Application System

As of March 30, 2022, Alberta Environment and Parks ("AEP") no longer uses the Water Act Temporary Diversion Licence Electronic Review System ("WATERS") to receive temporary diversion licence ("TDL") applications. Starting April 4, 2022, TDL applications processed by AEP must be submitted to its new Digital Regulatory Assurance System.

This change does not affect TDL applications regulated by the AER. Applications for TDLs related to energy resource activities must continue to be submitted through WATERS.

A TDL can be issued under the *Water Act* to allow someone to divert and use surface and groundwater for up to a year. TDLs related to energy resource activities are issued by the AER. AEP issues all others.

ALBERTA UTILITIES COMMISSION

Hydrogen Inquiry, AUC Bulletin 2022-05

Greenhouse Gas Reductions - Hydrogen Roadmap

The AUC opened an inquiry on matters relating to hydrogen blending in natural gas distribution systems.

Following the Government of Alberta's Hydrogen Roadmap, issued in November 2021, the AUC was directed to inquire into and report to the Minister of Energy on matters relating to hydrogen blending into natural gas distribution systems. The Hydrogen Roadmap recognized that the adoption of clean hydrogen has the potential to significantly reduce greenhouse gas emissions by 2030, with the province enabling hydrogen blending into natural gas distribution systems as one method to reduce greenhouse gas emissions.

Scope of the AUC's Hydrogen Inquiry

The AUC will gather information and make findings or provide observations on:

- the role of regulated natural gas distribution systems and unregulated competitive markets for hydrogen blending into natural gas distribution systems up to 20 percent blending by volume;
- the impacts of blended hydrogen into low-pressure natural gas distribution systems;
- the safe and reliable delivery of blended hydrogen through natural gas distribution systems, including potential harmonization with municipal or other relevant safety standards;
- addressing regulatory ambiguity, removing unnecessary regulatory barriers, and improving certainty as required to enable hydrogen blending into natural gas distribution systems; and
- areas for future study relating to hydrogen blending into natural gas distribution systems.

The AUC will explore critical issues related to hydrogen in natural gas distribution systems, including legislation, delivery of services to municipal and rural natural gas consumers, safety, blending standards and thresholds, rate impacts, and other issues.

Participation

The AUC decided that it will not determine standing in this proceeding, and parties may submit their written comments at the same time as they register to participate.

Alberta Utilities Commission 2023 Generic Cost of Capital, AUC Decision 27084-D01-2022

Return on Equity

In this decision, the AUC approved a return on equity ("ROE") of 8.5 per cent and a deemed equity ratio of 37 per cent (39 per cent for Apex Utilities Inc.) (collectively "Parameters") for 2023 on a final basis. The Parameters apply to the following utilities:

- AltaLink Management Ltd.("AML");
- Apex Utilities Inc. ("AUI");
- ATCO Electric Ltd. ("AE");
- ATCO Gas & Pipelines Ltd. ("AGP");
- ENMAX Power Corporation ("ENMAX");

- EPCOR Distribution & Transmission Inc. ("EDT");
- FortisAlberta Inc. ("Fortis");
- KainaiLink L.P.;
- City of Lethbridge;
- PiikaniLink L.P.;
- The City of Red Deer; and
- TransAlta Corporation.

The Parameters do not apply to EPCOR Energy Alberta GP Inc. or ENMAX Energy Corporation because they are regulated under the *Electric Utilities Act* ("*EUA*") and the *Regulated Rate Option Regulation*. Similarly, the Parameters do not apply to Direct Energy Regulated Services as default service provider under the *Gas Utilities Act* ("*GUA*") and the *Default Gas Supply Regulation*.

Background and Procedural Summary

Under the *Public Utilities Act* ("*PUA*"), the *GUA*, and the *EUA*, the AUC is required to set a fair return for utilities to set just and reasonable rates for customers. The Parameters are the components of a fair return determined in a generic cost of capital ("GCOC") proceeding. While each of these statutes provides matters for the AUC to consider, there is no given method for determining a fair return.

The AUC held that determining just and reasonable rates requires the AUC to balance the interests of both the utility and its customers. Rates must provide the utility a reasonable opportunity to earn a fair return on invested capital while also ensuring that customers are not paying more than is required to maintain safe, reliable, and economic service. The AUC noted that, in applying its judgment, the AUC often assesses conflicting evidence on risk, including the differing interests and perspectives of debt and equity investors.

The AUC considered three factors when setting a fair return: comparable investments, capital attraction, and financial integrity. The AUC held these factors to be well-established and was satisfied that the fair return standard is met when the return satisfies these three factors while also understanding that a fair return is one component of the AUC's determination of just and reasonable rates. The AUC noted that another component of just and reasonable rates is a reasonable opportunity to recover costs and expenses, including capital costs, operating costs, taxes, and depreciation. In January 2022, the AUC initiated the 2023 GCOC proceeding. It issued a letter notifying interested parties that it would be bifurcating this proceeding The first stage, decided in this decision, established the parameters for 2023. The second stage will focus on 2024 and future years.

2023 Parameters and Completion of Current GCOC Proceeding

The AUC noted its recognition of the continuing uncertainty and volatility of financial markets due to the COVID-19 pandemic. In response, the AUC indicated that it was prepared to extend the cost of capital parameters previously approved for 2022 for one year.

Key Economic and Market Submissions

The AUC noted that it generally considers a number of key economic indicators and financial market conditions in determining a just and reasonable ROE and deemed equity ratios. Indicators include the interest rate environment, credit spreads, market volatility, and some other indicators that serve as inputs to and guide the outcome of the capital asset pricing model ("CAPM"). The AUC found that market volatility and inflationary pressures, especially regarding food and energy prices, have been amplified by the geopolitical risks, uncertainty, and global economic ramifications triggered by Russia's recent invasion of Ukraine. The AUC held that the evidence before it showed upward pressure associated with inflation and interest rates. Other indicators such as credit spreads and the market equity risk premium ("MERP") remained largely stable. However, market volatility remains elevated, making it difficult to forecast relevant economic conditions for 2023.

(a) Inflation, Interest Rate Increase and Credit Spreads

The utilities argued that the expected future path of the policy interest rate should place upward pressure on authorized ROEs and other rates of return in the capital markets. The AUC found that the utilities' preparedness to accept the current ROE of 8.5 per cent, combined with the ongoing and pervasive uncertainty regarding the timing and extent of future changes in inflation and interest rates, support a continuation of the current GCOC parameters into 2023.

(b) Market Equity Risk Premium

The AUC quoted the following description of MERP with approval: Like the cost of capital itself, the market equity risk premium is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can expect to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable and must be inferred or forecasted based on known market information.

Estimates of a forward-looking MERP are used as an input in the CAPM and the empirical capital asset pricing model (ECAPM). The greater the estimate of the forward-looking MERP, the higher the ROE generated by the CAPM and the ECAPM, all else being equal. Different approaches can be used to estimate the forward-looking MERP.

The AUC accepted the Consumers' Coalition of Alberta ("CCA")'s data and argument showing that the average annual MERP had remained largely stable since 2018. The AUC determined that the data supports a continuation of the current GCOC parameters.

(c) Market Volatility

The AUC considered market volatility and the lack of certainty and clarity in available market data relevant for determining the Parameters. The current elevated volatility and uncertain outlook were determined to likely affect economic and market fundamentals in 2023. The AUC found that the elevated market volatility supports a continuation of the GCOC Parameters.

(d) Business Risk and Earning Above Awarded ROE

Parties submitted conflicting assessments of changes to business risk since the 2018 GCOC decision. The ATCO Utilities/Apex/Fortis submitted that there have been significant transformations occurring in the utility industry since 2018, including an emphasis on decarbonization; a focus on environmental, social, and governance standards; the need for grid modernization; and changes in the way in which customers are receiving utility service. These utilities stated that they are directly affected by these transformations, and these changes engender risk and uncertainty for utilities at a level seldom witnessed in the past. Customer groups submitted that there has been little if any change in business risk. Some customer groups pointed to the utilities achieving actual ROEs in excess of the Commission-approved ROEs.

The AUC was of the view that historical earnings above or below the approved ROEs do not help to determine what the ROE for a future test period should be. The AUC was not persuaded that there was a quantifiable change in business risk that would require a change in the deemed equity ratios for 2023.

Comparable Returns on Equity

All utilities supported keeping the ROE at 8.5 per cent, and some argued that current economic indicators would lead to a higher ROE for 2023 if the AUC were to carry out a full GCOC proceeding. The AUC held that the objective of the GCOC is to consider the market expectation for the utilities raising the capital necessary to provide safe and reliable utility service in Alberta. The AUC noted that in setting the GCOC for the utilities in Alberta, other jurisdictions can be a useful indicator or benchmark for evaluating contemporaneous rates of return and whether return expectations are generally increasing or decreasing. The AUC observed that ROEs from other jurisdictions referenced by interveners or calculated using formulaic methodologies do not materially depart from the AUC's last approved 8.5 per cent figure. The AUC, therefore, concluded that information from other jurisdictions does not bring the AUC's approved ROE into question.

Conclusion

The AUC concluded that there is insufficient support to depart from the currently approved ROE and the deemed equity ratios. The AUC determined that maintaining the existing ROE of 8.5 per cent will, when combined with the existing deemed equity ratios, provide the utilities with a fair return for 2023. The AUC also saw no quantifiable business risk that would require a change in the deemed equity ratios for 2023. The AUC, therefore, found that the deemed equity ratios for 2023 should remain unchanged from 2022.

***AltaLink Management Decision on Preliminary Question Application for Review of Decision 26509-D01-2022 (Corrigenda) 2022-2023 General Tariff Applications and 2020 Direct Assigned Capital Deferral Account Reconciliation Application,* AUC Decision 27172-D01-2022**

Review and Variance - Opening Rate Base

In this decision, the AUC approved an application from AltaLink Management Ltd. ("AML") for review and variance of Decision 26509-D01-2022 (Corrigenda) (the "Decision") in part. The AUC allowed a review of s. 10.10 of the Decision, which addresses AML's proposed capital expenditures for its pipeline electrical interference mitigation program as part of AML's 2022-2023 general tariff application ("GTA") and direct assigned capital deferral account ("DACDA") reconciliation application. The AUC refused to review s. 9.5 of the Decision, which addressed reductions to AML's opening rate base connected with its wildfire mitigation plan.

Discussion

In its GTA, AltaLink applied for AUC approval of its applied-for revenue requirement for the 2022-2023 test period, among other things. In the Decision, the AUC denied portions of AML's applied-for revenue requirement. The portions denied include amounts related to AML's 2022 opening rate base connected with its wildfire mitigation plan and proposed capital expenditures for its pipeline electrical interference mitigation program.

In the Decision, the AUC approved capital additions in the amount of $1.505 million, as opposed to the applied-for amount of $3.052 million for AML's wildfire mitigation plan. The AUC denied all proposed capital expenditures connected with AML's pipeline electrical interference mitigation plan.

The Review Application

The review process has two stages. In the first stage, a review panel decides if there are grounds to review the original decision (the preliminary question). If the review panel decides to review the Decision, it moves to the second stage, where it decides whether to confirm, vary, or rescind the original decision (the variance question).

In this decision, the AUC considered the preliminary question.

Pipeline Electrical Interference Mitigation Issues

The AUC exercised the discretion to review the Pipeline Electrical Interference Mitigation Issue on its own motion pursuant to s. 2 of Rule 016: *Review of Commission Decisions ("Rule 016")*.

In the Decision, AML was denied all applied-for funds to carry out the work under the pipeline electrical interference mitigation program. However, AML is required to undertake this work to comply with applicable laws and standards. Given the requirement of AML to undertake this work, the review panel found that further inquiry into the Pipeline Electrical Mitigation Interference Issue is warranted.

Because the AUC determined a need to review this section of the Decision on its own motion, it found it unnecessary to review AML's proposed grounds for review in this regard.

Wildfire Opening Rate Base Issue

AML requested a review of s. 9.5 of the Decision under s. 5(1)(a) of *Rule 016* on the basis that the AUC made an error of fact or mixed fact and law where the legal principle is not readily extricable, which is material to the decision and exists on a balance of probabilities, with respect to the Wildfire Opening Rate Base Issue. AML argued that the AUC erred when it found that the scope of work approved by the AUC in relation to AML's targeted right-of-way improvements in high-risk fire areas and wildfire tree removals had changed from the scope of work that was approved on a forecast basis in Decision 23848-D01-2020.

AML also submitted that the AUC narrowly and inflexibly construed the approved scope of the transmission line rights-of-way upgrade in high-risk fire areas program by not allowing any of AML's actual capital expenditures to depart from the forecast.

In this review decision, the AUC determined that the asserted errors are not material to the outcome of the Decision and would not lead the review panel to vary or rescind the Decision regarding the GTA.

When assessing the GTA, the AUC performed a prudence assessment of the applied-for actual capital additions for the sub-projects within the transmission line rights-of-way upgrades in the high-risk fire areas program. In that review, the AUC found that AML had redefined and restated its work units and that the cost per unit had more than doubled from what the AUC had approved on a forecast basis in AML's previous GTA. The AUC was not satisfied with AML's justification for the increased actual costs of the sub-projects at issue. The review panel found no basis to question the hearing panel's findings.

The AUC found that the requirements to grant a review of this section were not met.

<u>Decision</u>

The AUC decided to review s. 10.10 of 26509-D01-2022 (Corrigenda) regarding capital expenditures for AML's pipeline electrical interference mitigation program. The application to review the findings regarding the opening rate base with respect to the wildfire mitigation plan was denied.

Balancing Pool Application for an Order Permitting the Sharing of Records Not Available to the Public Regarding the Vulcan Solar Project, **AUC Decision 27225-D01-2022**
Market Oversight and Enforcement - FEOC

In this decision, the AUC approved an application by the Balancing Pool for an order to permit the sharing of records pertaining to the Alberta energy market under s. 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

<u>Introduction and Procedural Background</u>

The Balancing Pool filed an application for permission to share records that are not available to the public between Balancing Pool, Concord Vulcan GP2 Ltd. ("Concord Vulcan"), Concord Vulcan Partnership ("CVP"), and URICA Energy Real Time Ltd. ("URICA"). The requested order relates to the 22-megawatt ("MW") Vulcan Solar Project (asset ID VCN1), located near the town of Vulcan.

<u>AUC Findings</u>

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

S. 7 of the *Small Scale Generation Regulation* states that "unless…request[ed] otherwise, the Balancing Pool (a) must act as the electricity market participant on behalf of the small scale power producer in dealings with the ISO in respect of the electric energy supplied by the small scale power producer's small scale generating unit." The AUC found that Concord Vulcan qualifies as a small scale power producer and is therefore represented as an electricity market participant by the Balancing Pool.

In its application, the Balancing Pool indicated that it has entered into commercial arrangements with URICA, which, among other things, appointed URICA as an agent of the Balancing Pool to provide 24-hour real-time dispatch-desk service for operational energy market services and energy restatements for events at VCN1. These arrangements will make it necessary for the Balancing Pool, Concord Vulcan, CVP, and URICA to share certain records that are not otherwise available to the public, including operational and dispatch information, energy price, volume pairs, and available capability.

The AUC was satisfied that the Balancing Pool had demonstrated that (i) the sharing of records is reasonably necessary for it to carry out its business; and (ii) that the subject records would not be used contrary to the fair, efficient, and openly competitive operation of the Alberta electricity market, including the conduct referred to in s. 2 of the *FEOC Regulation* and that the applicants would conduct themselves in a manner that would support the fair, efficient and openly competitive operation of the market.

The AUC further found that the offer control limit of the entities was less than 30 per cent, as required by Subsection 5(5) of *FEOC Regulation*. The AUC noted that the Market Surveillance Administrator ("MSA") supported the application.

Given the mandate of the MSA under Subsection 39(2)(a)(vi) of the *Alberta Utilities Commission Act*, the AUC considered the MSA's support of this application to have been a contributing factor in the decision to permit the sharing of records.

The AUC approved the applied-for sharing of records, subject to terms and conditions set out in the decision.

***BER Hand Hills Wind GP Inc. and ATCO Electric Ltd. Hand Hills Wind Power Plant Connection,* AUC Decision 27008-D01-2022**
Wind - Facilities

In this decision, the AUC approved the application from BER Hand Hills Wind GP Inc. ("BER") and ATCO Electric Ltd. ("ATCO") for the Hand Hills Wind Power Plant (the "Power Plant") connection. The AUC determined that approval of the application, including the preferred route for the new transmission line, is in the public interest. The AUC denied BER's application for an interconnection order.

Introduction

BER has AUC approval to construct and operate the 145-megawatt (MW) Power Plant in Delia, Alberta. It also has the approval to construct and operate the wind project substation, designated as Highland 572S Substation.

BER requested system access from the Alberta Electric System Operator ("AESO") to connect the Power Plant to the Alberta Interconnected Electric System. The AUC approved the needs identification document ("NID") application filed by the AESO in response to BER's request. In the NID application, the AESO proposed constructing a 9.6-kilometre ("km") transmission line to connect the Highland 572S Substation to existing Transmission Line 7L128 using a T-tap configuration and to add or modify other equipment needed to ensure proper integration of the Project with the grid.

To meet the need identified by the AESO, BER and ATCO sought approval of the detailed design, specific location, routing, and equipment from the AUC.

<u>BER Hand Hills Wind GP Inc. Facility Application</u>

BER applied to the AUC for approval to construct and operate a 144-kilovolt transmission line designated Transmission Line 7LA128.

The AUC found that the facility application filed by BER under ss. 14, 15, 18, and 19 of *the Hydro and Electric Energy Act* ("*HEEA*") complied with the information requirements prescribed in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* and was consistent with the NID approval. The AUC was further satisfied that the participant involvement program met the requirements of Rule 007.

BER set out a preferred route and an alternate route in its application. BER explained that a greater length of the preferred route would be located along developed roads than the alternate route. 3.2 km of the alternate route would be located within undeveloped road allowance. The alternate route would require more brushing and be less accessible from an operations and maintenance perspective. Stakeholders also indicated their preference for the transmission line to be sited along a developed roadway such as Township Road 170, which the preferred route would follow.

Both the preferred and alternate routes require a 1.65 km distribution line to be salvaged. The AUC accepted BER's submission that the preferred route requires less distribution construction coordination and would incur fewer relocation costs for the distribution line than the alternate route. BER submitted that the preferred route is the environmentally preferred route. BER confirmed that it would consult with Alberta Environment and Parks before any construction-related activities commence during the restricted activity periods for sharp-tailed grouse and ferruginous hawk.

The AUC determined that the environmental impact favours the preferred route. The AUC found that implementation of the mitigation measures outlined in both the environmental evaluation and environmental protection plan would reduce the environmental effect of the proposed transmission line to an acceptable level.

The AUC approved the preferred route and approved its construction and operation under s. 17 of the *Alberta Utilities Commission Act* ("*AUCA*").

<u>ATCO Electric Ltd. Facility Application</u>

ATCO applied for approval to alter existing Transmission Line 7L128 to accommodate a T-tap connection to BER's proposed transmission line. ATCO also applied for a connection order to connect its transmission line to BER's proposed transmission line, thereby connecting the Hand Hills Wind Power Plant to the Alberta Interconnected Electric System.

The AUC found that ATCO's facility application complies with all applicable requirements of Rule 007 and ss. 14, 15, 18, and 19 of the *HEEA*. The AUC approved the application according to s. 17 of the *AUCA*.

<u>Decision</u>

The AUC approved the application to construct and operate Transmission Line 7LA128 filed under ss. 14, 15, and 19 of the *HEEA* by BER Hand Hills Wind GP Inc. BER's application for a connection order was denied. As this order will be issued to ATCO, approval of BER's application was unnecessary.

Under ss. 14, 15, 18, and 19 of the *HEEA*, the AUC approved ATCO's application for permission to alter and operate Transmission Line 7L128 and connect Transmission Line 7L128 to Transmission Line 7LA128.

***Calgary District Heating Inc. Exemption from Provisions of the Public Utilities Act,* AUC Decision 26717-D01-2022**

Rate Regulation - Exemption

In this decision, the AUC approved an application from Calgary District Heating Inc. ("CDHI") requesting that the Downtown District Energy Centre ("DDEC") be exempt from provisions of the *Public Utilities Act* ("*PUA*") and the reporting requirements under Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

Background and Procedural Summary

The DDEC is a thermal district energy system that provides district energy (in the form of central heating and hot water services) to commercial, municipal, and residential buildings in downtown Calgary. The DDEC is a public utility owned by CDHI, as defined in the *PUA*. CDHI acquired the DDEC from ENMAX Corporation ("ENMAX") in 2021. Following the purchase, CDHI confirmed that the facility would no longer be municipally owned and subject to the exemption in s. 78(2) of the *PUA*. As a result, the entirety of the *PUA* would apply to the DDEC and CDHI as its owner.

CDHI requested an order under ss. 8 and 9 of the *Alberta Utilities Commission Act* and s. 79 of the *PUA*, declaring that:

(a) ss. 88(a), (d) and (e), 92, and 103 of the *PUA* do not apply to any of the DDEC, CDHI, and the goods and services produced by the DDEC and offered or provided by CDHI;

(b) the reporting requirements under Rule 005 do not apply to the DDEC and CDHI; and

(c) the requirements of ss. 88(a) and (d) of the *PUA* and Rule 005 be replaced with specific specified annual reporting of key metrics to the AUC.

CDHI argued that its requests were in the public interest and represented a flexible and proportionate form of light-handed regulation that was responsive to the nature of district energy services. CDHI emphasized that the AUC would retain oversight of the services provided by the DDEC on a complaint basis.

ATCO Gas intervened in the proceeding and requested that the application be denied, or alternatively, should the AUC grant the exemptions, that CDHI be limited to serving its existing customers. ATCO Gas maintained that the applied-for exemptions would result in harm to customers and create an unlevel playing field between CDHI and other regulated utilities.

Jurisdiction

The AUC is empowered to declare that certain provisions of the *PUA* do not apply to certain goods or services provided by a public utility under s. 79(1) of the *PUA*.

ATCO Gas submitted that, in determining whether to make a declaration under s. 79(1) of the *PUA*, the AUC must exercise its discretion consistently with the legislative scheme. ATCO Gas argued that granting CDHI's requested exemptions would frustrate the purpose of the *PUA* and the broader legislative scheme, which is to protect customers from the exercise of monopoly power through prospective regulation.

ATCO Gas argued that granting the exemptions requested by CDHI would undermine the legislature's express intention to establish prospective rate regulation.

The AUC disagreed that a departure from prospective economic regulation would necessarily frustrate the purpose of the *PUA* or undermine the intent of the legislature. The AUC found that it must exercise its discretion within the framework provided by the legislation and consistently with the purposes and policies underlying its grant. The AUC held that the overarching objective of the legislative scheme is to safeguard the public interest in a service environment that is susceptible to abuses of monopoly power. The legislature has equipped the AUC with the tools required to fulfill this purpose, including the ability to fix rates and exercise general oversight of the operation of public utilities.

The AUC was satisfied that most of the exemptions requested by CDHI could be granted without harming customers or interfering with the integrity of utility service.

Issues

Will the Regulation Proposed by CDHI Interfere with the Establishment of Just and Reasonable Rates

The *PUA*, as well as the *Electric Utilities Act* ("*EUA*") and *Gas Utilities Act* ("*GUA*"), require the AUC to ensure the establishment of just and reasonable rates. Rate regulation is not generally exercised in competitive markets where customers have a choice of providers, as it is intended to operate as a surrogate for competition where competition is absent and is unnecessary where the market will otherwise function on its own.

ATCO Gas asserted that the DDEC has all the characteristics of a natural monopoly and that its customers require protection from the abuse of monopoly power. ATCO Gas argued that CDHI customers do not have a choice of options. ATCO Gas relied on AUC Decision 24056-D01-2019 regarding the application from ENMAX Independent Energy Solutions Inc. ("EIES") for exemption of the Edmonton District Energy System from sections of the *PUA*. In Decision 24056, the AUC found that customers who agreed to take service from the Edmonton District Energy System were effectively captive to the services from EIES. The AUC was not convinced by the reference to this decision and determined that the current circumstances of CDHI are not comparable to those between EIES and its customers.

In contrast to Decision 24056, the AUC would retain oversight and authority to consider rates on a complaint basis in the circumstances of this matter. Further, CDHI submitted at the hearing that it could accept the AUC's authority to fix rates for affected customers or a customer class if, following a customer complaint, the AUC determined that rates charged by CDHI were unjust or unreasonable.

The AUC determined that CDHI operates in a sufficiently competitive environment to allow its customers a degree of choice about their service provider that would not exist in a monopoly.

What are the Effects of the Application on Safety, Reliability and Integrity of the Utility System

The AUC found no evidence to suggest that the exemptions proposed by CDHI will impact the safety or reliability of service offered to customers of the DDEC.

ATCO Gas submitted that approval of the application would result in an unlevel playing field between the DDEC and other utilities subject to more extensive regulation, which would result in an unfair shifting of costs to regulated customers. ATCO Gas is the default supplier of natural gas in the city of Calgary and operates as a natural monopoly. CDHI can choose which customers to serve, taking those with the highest throughputs and greatest possible profits while ignoring less or non-profitable customers. This can contribute to higher prices for remaining customers, initiating a cycle of defecting customers and increasing costs.

The AUC was not convinced that approval would harm existing ATCO Gas customers. The AUC was not convinced as ATCO Gas did not provide detailed evidence supporting the harm. CDHI is also a customer of ATCO Gas, and the DDEC uses natural gas as an input in providing heat to its customers. The AUC accepted that ATCO Gas could lose some customers to the DDEC. The AUC, however, determined that the DDEC's continuing operation or expansion within its current capacity will not alter the character of ATCO Gas' statutory obligation to serve customers within its franchise area, impair ATCO Gas' ability to charge just and reasonable rates to its customers, or limit its opportunity to recover its prudently incurred costs and earn a fair rate of return.

Conclusion

As a condition of approval, the AUC imposed that CDHI provides, within 30 days of this decision, a written notice to its existing customers of their entitlement to raise complaints with the AUC in respect of the district energy service provided by CDHI or rates paid for that service. Further, upon executing any new thermal energy services agreements, CDHI shall notify customers of their entitlement to raise complaints with the AUC regarding the district energy service provided by CDHI or rates paid for that service. Finally, CDHI shall file with the AUC an annual report of key metrics. CDHI must file the report no later than 60 days following the completion of CDHI's corporate unaudited financial year-end for each calendar year.

The AUC determined that it is in the public interest to allow the exemption of the DDEC and CDHI as its owner from specific provisions of the *PUA.* The AUC found it unnecessary to grant the requested exemption from s. 92 of the *PUA*. The AUC declared that ss. 88(a), (d) and (e), and 103 of the *PUA* and the reporting requirements under Rule 005 do not apply to DDEC and CDHI.

Calgary Energy Centre No. 2 Inc. Power Plant FD6 Maintenance Upgrade Project, **AUC Decision 27105-D01-2022**
Facilities - Gas

In this decision, the AUC approved the request from Calgary Energy Centre No. 2 Inc. ("CEC2") to alter approval for the Calgary Energy Centre Power Plant (the "Power Plant") to reflect an increase in the total generating capability from 330 megawatts ("MW") to 360 MW.

Application

ENMAX Energy Corporation ("ENMAX"), on behalf of CEC2, filed an application seeking an amendment to the approval for the Power Plant under ss. 11 and 12 of the *Hydro and Electric Energy Regulation* ("*HEER*").

The Power Plant currently consists of a 190-MW natural gas-fired combustion turbine generator and a 140-MW steam turbine generator. The turbine blades will be removed as part of scheduled maintenance, and the replacement blades will increase the output of the natural gas turbine by 30 MW. The increase only pertains to the natural gas turbine output and would not change the steam turbine output.

Findings and Decision

The AUC determined that the proposal is minor, no person would be directly and adversely affected by the proposal, and the proposed alterations will cause no significant adverse environmental impact. The AUC, therefore, found that the requirements of s. 11 of the *HEER* would be met.

CEC2 stated that there would be no emission intensity or noise change and that the Power Plant would continue to comply with the *Environmental Protection and Enhancement Act*. CEC2 confirmed that the Power Plant would remain in compliance with AUC Rule 012: *Noise Control*, Alberta Electric System Operator rules, operating procedures, and standards in all respects after the increase in capability.

The AUC approved the request to alter and operate the Power Plant.

City of Lethbridge 2021-2023 General Tariff Application Compliance Filing, **AUC Decision 27213-D01-2022**
GTA - Compliance Filing

In this decision, the AUC evaluated the compliance filing of the City of Lethbridge ("Lethbridge") following Decision 26554-D01-2022 (the "Decision") regarding Lethbridge's general tariff application. In this compliance filing decision, the AUC was satisfied that Lethbridge complied with the directions issued in the Decision. The AUC approved Lethbridge's 2021-2023 revenue requirement on a final basis, as filed.

Introduction

Lethbridge is a transmission facility owner ("TFO") under the *Electric Utilities Act* ("*EUA*"). As a TFO in Alberta, Lethbridge provides regulated transmission services and recovers the transmission service costs through a transmission tariff. The Alberta Electric System Operator must approve this tariff.

In Decision 26554-D01-2022, the AUC considered whether Lethbridge's tariffs to recover its forecast operating costs for 2021, 2022, and 2023 were just and reasonable and would provide a fair rate of return on and of Lethbridge's capital investment. The AUC determined that specific costs applied for by Lethbridge were not reasonable or required clarification and directed Lethbridge to provide a compliance filing to address certain directions before the AUC could approve Lethbridge's 2021-2023 revenue requirements as final.

Compliance with Directions from Decision 26554-D01-2022 and Interim Rates True-up

In the Decision, the AUC issued seven directions for Lethbridge to address before the AUC would approve the applied-for 2021-2023 revenue requirements on a final basis. Two of the seven directions are to be addressed in future applications, while the remaining five directions were required to be addressed in Lethbridge's compliance filing.

Direction 2 required that Lethbridge treat the approved single aggregated "accumulated net salvage account" in the same manner as Lethbridge's accumulated depreciation accounts, where the balance of the account determines the rate base. Direction 3 required an adjustment to the Universal System of Accounts ("USA"). The AUC denied the applied-for -45 percent net salvage for USA Account 356.00 - Transmission Lines, and Lethbridge was directed to incorporate the previously approved net salvage of -40 percent for this account.

Direction 4 required that Lethbridge explain the differing December 31, 2019, book (or actual) balances between its depreciation study and minimum filing requirement schedules. Lethbridge was also required to adjust its amortization of reserve differences calculation, and annual true-up provision, if necessary. In Direction 5, the AUC required that Lethbridge reports its December 31, 2019, actual net salvage by USA account. Finally, Direction 7 required that Lethbridge provides clarification regarding the function fleet capital additions for 2022 and 2023.

The AUC found that Lethbridge had complied with directions 2, 3, 4, 5, and 7.

Lethbridge proposed that its total April 2022 payment be $1,098,737, which consists of the sum of the 2022 monthly tariff of $785,202, and a one-time lump sum payment of $313,535 to true up interim rates to the final rates from January 2021 to March 2022.

The AUC found that the annual tariff and monthly rates for the 2021-2023 test period corresponded to the respective revenue requirements and approved the same on a final basis. The AUC also approved a one-time lump sum payment of $313,535 to be collected from the AESO for the revenue shortfall resulting from the difference between Lethbridge's interim and approved monthly tariffs between January 1, 2021, and March 31, 2022.

Order

The AUC approved Lethbridge's 2021-2023 revenue requirements of $9,344,977 for 2021, $9,422,427 for 2022 and $9,835,995 for 2023 as final.

EPCOR Distribution & Transmission Inc. Compliance Filing to Decision 26836-D01-2021, **AUC Decision 27153-D01-2022**

Rates - Compliance Filing

In this decision, the AUC evaluated EPCOR Distribution & Transmission Inc.'s ("EDTI") compliance with the directions issued in Decision 26836-D01-2021 regarding EDTI's 2022 system access service ("SAS") Phase 2 application (the “Decision”). The AUC determined that EDTI had complied with the AUC’s directions and approved the resulting SAS rates, effective April 1, 2022.

Compliance with Commission Directions

In the Decision, the AUC approved EDTI’s proposal to modify its 2022 SAS rate design to include a monthly non-coincident peak metered demand charge for several of its commercial and industrial customer rate classes. EDTI was directed to file a compliance filing, incorporating the latest available information in its SAS rates before the SAS rates became effective on April 1, 2022.

EDTI updated its SAS rates to incorporate the Alberta Electric System Operator’s approved 2022 demand transmission service rates as well as the forecasted approved billing determinants, pool price, and operating reserve percentages dealing with EDTI’s 2022 annual performance-based regulation rate adjustment.

Resulting 2022 SAS Rates

EDTI calculated its 2022 SAS rates using the general principles and methodologies approved in Decision 26836-D01-2021 and Decision 26852-D01-2021. The AUC reviewed the typical bill impacts from March 2022 to April 2022 to assess the likelihood of rate shock resulting from the proposed 2022 SAS rates and the changes in the rates as a result of compliance with the directions issued in the Decision.

The AUC determined that the month-over-month changes to total bundled customer bills from March 2022 to April 2022 are minimal. The bill impacts for individual customers in the rate classes affected by the proposed changes to EDTI’s SAS rate design were considered and accepted by the AUC in Decision 26836-D01-2021.

Order

The AUC found that EDTI complied with the directions issued in Decision 26836-D01-2022 and approved the resulting SAS rates, effective April 1, 2022.

Melcor Developments Ltd., Highview Communities Inc. and Sunset Properties Inc. Complaint Regarding FortisAlberta Inc. Changing Design Standards, **AUC Decision 26649-D01-2022**
Complaint - Rates

In this decision, the AUC dismissed the complaint filed by Melcor Developments Ltd., Highview Communities Inc., and Sunset Properties Inc. (the “Melcor Entities”). The Melcor Entities’ complaint related to changed design standards and associated costs imposed by FortisAlberta Inc. (“FortisAB”) for the design and installation of underground electrical distribution systems to service lands owned by the Melcor Entities.

Decision and Order

The AUC was not convinced by the claims made in the complaint. As a result of the dismissal, the costs paid to FortisAB for the installation and construction of the underground electrical distribution systems servicing Lanark Landing, Phase 1C and Sunset Ridge, Phase 22B, are no longer subject to the interim relief granted by the AUC.

The AUC was not persuaded that the design standards applicable to the developments that are the subject of the proceeding (a) were imposed in a manner inconsistent with a proper application of Fortis’s approved customer terms and conditions of service; (b) result in unduly discriminatory electric distribution service and costs; and/or (c) were implemented in a manner that is unjust, unreasonable, unduly preferential, arbitrary or unjustly discriminatory, or inconsistent with or in contravention of law.

The Melcor Entities’ complaint was consequently dismissed.

***NuVista Energy Ltd. Wembley Thermal Power Plant, Industrial System Designation and Interconnection,* AUC Decision 27017-D01-2022**
Facilities - Industrial System Designation

In this decision, the AUC approved applications from NuVista Energy Ltd. ("NuVista") to construct and operate a new thermal power plant, to connect the thermal power plant to the Alberta Interconnected Electric System ("AIES"), and for an industrial system designation ("ISD") that encompasses all electric facilities at the existing Wembley Gas Plant.

Introduction

NuVista owns and operates the Wembley Gas Plant (gas plant) in the La Glace area, approximately 25 kilometres north of the town of Wembley. NuVista applied for permission to construct and operate a 16.4-megawatt ("MW") natural gas-fired power plant, designated as the Wembley Thermal Power Plant (the "Power Plant") within the existing boundary of the Wembley Gas Plant site.

The Power Plant would consist of eight Caterpillar G3520C natural gas-fired reciprocating engine generators, with a total generating capability of 16.4 MW, and a waste heat recovery system. Heat recovered through an installed water jacket cooling system and from the exhaust would provide approximately 11 MW of thermal heat energy for specific gas plant processes, which would offset the need for fuel gas consumption and associated emissions. NuVista estimated that 4.8 MW of excess power would be exported to the AIES.

Following the notice of application, the AUC received statements of intent to participate from AltaLink Management Ltd., ATCO Electric Ltd., and Heartland Generation Ltd. The statements of intent to participate commented on the broader issues related to Bill 86 regarding enabling self supply and export and s. 117(2) of the *Electric Utilities Act* ("*EUA*")*.* Under s. 117(2) of the *EUA*, under certain circumstances, the AUC may impose the condition that the owner of the industrial system be responsible for paying a just and reasonable share of the costs associated with the interconnected electric system. The AUC found that this proceeding was not an appropriate forum to discuss this issue. Consequently, the AUC denied AltaLink Management Ltd., ATCO Electric Ltd., and Heartland Generation Ltd. standing.

Is Approval of the Industrial System Designation in the Public Interest

The AUC determined that the application met the information requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines.* The participant involvement program conducted by NuVista was also found to have complied with Rule 007.

The Noise Impact Assessment ("NIA") submitted with the application concluded that mitigation measures were needed to allow the Power Plant to meet the permissible sound levels set out in Rule 012: *Noise Control*. NuVista undertook to implement the required noise control items proposed in the NIA. Relying on NuVista's undertaking, the AUC accepted that the Power Plant would comply with the requirements of Rule 012.

NuVista has committed to implementing mitigation measures to reduce environmental impacts, including potential impacts to trumpeter swans and an identified eagle nest. In addition, NuVista applied for an updated *Environmental Protection and Enhancement Act* approval to incorporate the Power Plant.

The AUC found NuVista's environmental evaluation to meet the requirements of Rule 007. The AUC was satisfied that with diligent implementation of the mitigation measures outlined in the environmental evaluation, the identified environmental effects of the project would be mitigated to an acceptable degree.

Does the Wembley Thermal Power Plant and Electric Facilities Meet the Requirements to be a Designated Industrial System

The AUC considered the ISD application in accordance with the principles and criteria set out in s. 4 of the *Hydro and Electric Energy Act* ("*HEEA*"). The AUC stated that, read broadly, s. 4(4) permits an ISD where the development of on-site generation is 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 AUC noted its understanding that NuVista sought an ISD to connect to the AIES with the intent to export electricity produced by the Power Plant in excess of the facilities' electricity load. NuVista has stated that it would use the 11 MW of thermal energy for the gas plant's glycol heating requirements and that connecting to the AIES would improve the Power Plant's efficiency. The AUC was satisfied that the proposal to export the excess electricity will facilitate efficient exchange with the AIES of electric energy in excess of NuVista's electricity requirements.

The AUC was satisfied that NuVista was not seeking the ISD to avoid system costs, as required by s. 4(2) of the *HEEA*. The AUC found that the requirements of s.4(3)(c) were not met because the components of the industrial operations are not under common ownership. Six companies have an interest in the gas plant, but NuVista has the largest interest in the gas plant and would own the Power Plant as of the date of the application. The other parties with interest in the gas plant did not object to the ISD application. The AUC, however, was satisfied that all of the separately owned components and all of the industrial operations are components of an integrated industrial process, and the proposed ISD consequently met the requirements of s. 4(4) of the *HEEA*.

The AUC noted that an ISD is intended to support generation that is needed and used for integrated industrial processes under s. 4(3)(d) of the *HEEA*. NuVista acknowledged that the generation capacity exceeds the gas plant's electricity needs but stated that all waste heat produced by the generating units would be utilized.

The AUC determined that NuVista's proposal met the principles and criteria for an ISD set out in s. 4 of the *HEEA.*

AUC Decision

Pursuant to ss. 11 and 18 of the *HEEA*, the AUC approved the applications to construct and operate the Power Plant and to connect it to the ATCO Electric Ltd. distribution system. The AUC further granted the ISD application under s. 4 of the *HEEA* and ss. 2 and 117 of the *EUA*.

***TransAlta Corporation, as Manager of TransAlta Generation Partnership Application for Interim Order Directing AltaLink Management Ltd. to Perform its Obligations Under the Operations and Maintenance Agreement,* AUC Decision 27168-D01-2022**

Jurisdiction - Arbitration

In this decision, the AUC approved an interim order directing AltaLink Management Ltd. ("AML") to comply with its obligations under the Operations and Maintenance Agreement dated April 29, 2002, between it and TransAlta Corporation (the "O&M Agreement") until the outcome of arbitration is determined.

Background

TransAlta Generation Partnership ("TransAlta") sold the entirety of its transmission business and assets to AML, with the exception of certain assets located on 13 First Nations lands in areas south of Edmonton (the "Withheld Assets"). TransAlta still owns the Withheld Assets. TransAlta and AML also entered into the O&M Agreement under which AML performed services, such as inspection, repair, maintenance, reclamation, capital projects, and administrative services (the "Services") since April 29, 2002, in connection with the Withheld Assets.

On December 14, 2020, AML provided a notice of termination to TransAlta, indicating it would cease providing the Services as of April 29, 2022, the date when the initial term of the O&M Agreement expires. TransAlta opposed the termination. TransAlta submitted that the parties had engaged in negotiations as required by provisions in the

O&M Agreement. Following unsuccessful negotiations, TransAlta commenced arbitration. Given that it is uncertain that the outcome of arbitration will be known by April 29, 2022, TransAlta filed the current application with the AUC to compel AltaLink to comply with its obligations under the O&M Agreement, pending the conclusion of arbitration.

Should the AUC Grant TransAlta the Interim Order

The AUC noted TransAlta's responsibility to ensure the assets are operated and maintained in a safe, reliable, and economic manner. However, because the Withheld Assets are located within AML's service territory and are integrated with AML's transmission system, the AUC was concerned that safe and reliable service to customers could be adversely and abruptly impacted if AML ceases to perform its services.

The AUC determined it to be in the public interest to grant the interim order and noted that it made no findings with respect to the terms of the O&M Agreement. The AUC emphasized that its decision to grant the interim order is made in discharging its public interest mandate as it pertains to the safe, reliable, and economic operation of Alberta's transmission system. It is also consistent with Decision 2002-038, wherein the Alberta Energy and Utilities Board, the predecessor to the AUC, found that preserving the *status quo* would ensure continued safe and reliable service and not unduly increase costs to consumers.

Does the AUC Have the Jurisdiction to Grant the Interim Order

Both TransAlta and AML provided submissions on the AUC's jurisdiction to grant the requested relief. AML submitted that because AML will no longer fit the definition of an owner of a transmission facility under the *Electric Utilities Act* ("*EUA*") or public utility in the *Public Utilities Act* ("*PUA*"), the AUC does not have jurisdiction to grant the requested relief.

Under the *EUA,* an owner of a transmission facility includes the operator of that facility.12 Transmission facilities meeting certain criteria are considered electric utilities. The *PUA* similarly defines the owner of a public utility to include operators.

The AUC found that by virtue of operating the Withheld Assets, AltaLink is currently an "owner" of a transmission facility/electric utility under the *EUA* and "owner" of a public utility under the *PUA* and is subject to the AUC's jurisdiction and oversight. The AUC will make a final decision regarding the interim order once the outcome of arbitration is determined.

Order

The AUC granted the applied-for order on an interim basis directing AML to continue to perform its obligations set out in the O&M Agreement until the outcome of an ongoing arbitration process is determined and the AUC makes a final determination regarding the interim order. As the order was issued on an interim basis, TransAlta Corporation was directed to file a new application with the AUC within seven days after receipt of the arbitration decision.

***Versorium Energy Ltd. Northern Valley 1 Distributed Energy Resource Power Plant,* AUC Decision 27132-D01-2022**

Power Plant - Facilities

In this decision, the AUC approved applications from Versorium Energy Ltd. ("Versorium") to construct and operate a 5.044-megawatt ("MW") natural gas-fired Northern Valley 1 Distributed Energy Resource power plant (the "Power Plant") and to connect the Power Plant to ATCO Electric Ltd.'s distribution system (the "Project").

Applications

Versorium applied for permission to construct the Project on private land, including cultivated and adjacent modified grassland, 14 kilometres southeast of Elk Point. The Project includes two gas-fired reciprocating engines with a nominal capability of 5.044 megawatts, a switchgear building, a generator step-up transformer, a low-pressure natural gas pipeline to connect to the County of Vermilion River's natural gas system, and a distribution line to connect to ATCO Electric Ltd.'s distribution system.

Findings

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

Based on reports and evaluations submitted as part of the application, the AUC determined that the Project will be compliant with Rule 012: *Noise Control*, *Alberta Ambient Air Quality Objectives,* and federal *Multi-Sector Air Pollutant Regulations.*

Versorium submitted an *Environmental Protection and Enhancement Act* application to Alberta Environment and Parks but had not received feedback on the application at the time of this decision.

Decision

The AUC determined that, in accordance with s. 17 of the *Alberta Utilities Commission Act*, approval of the applications is in the public interest. The AUC approved the applications to construct and operate the Power Plant and connect the Power Plant to ATCO Electric Ltd.'s distribution system under ss. 11 and 18 of the *Hydro and Electric Energy Act*.

CANADA ENERGY REGULATOR

Foothills Pipe Lines (South BC) Ltd. Application for the Foothills Zone 8 West Path Delivery 2023 Project, CER Letter Decision C17973 - A8C3E6

Leave to Open - Exemption

In this decision, the CER approved an application by Foothills Pipe Lines (South BC) Ltd. ("Foothills") for an exemption from the provisions of ss. 180(1)(a) and 198 of the *Canadian Energy Regulator Act* ("*CER Act*") for the Foothills Zone 8 West Path Delivery 2023 Project (the "Project"). Foothills also requested an exemption from the requirements of ss. 180(1)(b) and 213(1) to obtain leave to open ("LTO") from the CER prior to the installation of the hot tap tie-in assembly.

Application and Project Overview

Foothills sought approval for the construction and operation of a single loop of approximately 32 km of 1219 mm Nominal Pipe Size ("NPS") 48 natural gas pipeline that will loop the existing British Columbia Mainline and the Foothills South BC Pipeline (the "Elko Section") and an expansion of the Kingsgate Border Meter Station ("Kingsgate Border MS").

The proposed Elko Section is located 17 km east of the Town of Fernie, British Columbia. It will be built on Federal Crown freehold land (90 percent), private freehold land (8 percent), and provincial Crown land (2 percent).

The purpose of the Project is to increase capacity on the Foothills South BC (Zone 8) system to meet existing and incremental contractual obligations. The Project is underpinned by approximately 162 terajoules per day (TJ/d) of incremental Firm Transportation Delivery service on the Foothills South BC system from the Alberta-British Columbia Border to the Kingsgate Border MS. The Kingsgate Border MS component aims to expand the capacity of existing metering facilities by replacing 14 orifice-meter plates with larger diameter orifice-meter plates within the existing meter station site.

The Application Assessment Process

Following the notice of application filed by the CER on March 24, 2021, the CER received letters of comment from Elk Valley Métis Association ("EVMA"), Western Export Group ("WEG"), and the Nature Conservancy of Canada.

Foothills' Engagement with Indigenous Peoples

The CER was satisfied that Foothills had appropriately notified and engaged with potentially impacted groups and that Foothills' commitment to continue engagement activities throughout the lifecycle of the Project was appropriate.

Condition 10 requires Foothills to file information about any ongoing engagement activities with Indigenous peoples and Foothills' responses to any concerns raised with the CER. The CER invited comments on draft Condition 10 but received no comments. Foothills proposed that Condition 10 be struck because the CER has not issued this condition on other recent projects of comparable scope and scale and with a similar level of interest or concerns expressed by Indigenous communities. The CER was of the view that the deciding factors in imposing this type of condition are the type of engagement by a company and whether the engagement is ongoing, rather than the particular scope and scale of a project and as such imposed Condition 10 as a condition of approval of the Project.

EVMA Letter of Comment

The EVMA filed a letter raising concerns about inadequate consultation, lack of capacity to effectively participate in the Environmental and Socio-Economic Assessment ("ESA"), and lack of capacity to undertake a traditional land use assessment. The letter also identified concerns about the proposed Project's potential impacts on the environment, traditional land and resource use, socio-economic factors, and s. 35 rights of EVMA.

The CER considered the concerns raised by the EVMA, Foothills' response to those concerns, and Foothills' ongoing engagement with EVMA. The CER also considered Foothills' stated efforts to support the EVMA's Traditional Knowledge study and Foothills' commitment to evaluate and adjust its planned mitigation measures as needed upon receipt of that study. The CER further noted that Condition 11 of the approval conditions would require Foothills to report on any outstanding Traditional Knowledge studies, including EVMA's study before construction begins.

The CER determined that the issues raised by EVMA could be addressed through Foothills' commitments and proposed mitigation measures and through compliance with Condition 10 and Condition 11. The CER was satisfied that Foothills' commitment to continue engaging with EVMA, including engagement capacity funding and funding for a Traditional Knowledge study, demonstrates Foothills' efforts to continue learning about and responding to EVMA's concerns with the Project. The CER was further satisfied that Foothills' Indigenous relations business engagement activities demonstrate Foothills' efforts to provide employment and economic opportunities for Indigenous peoples, which is responsive to the socio-economic concerns raised by EMVA.

<u>Crown Consultation and Potential Impacts of the Project on the Rights of Indigenous Peoples</u>

Foothills stated that residual effects of the Project on the exercise or practice of the rights of Indigenous peoples recognized and affirmed by s. 35 of the *Constitution Act, 1982* are likely to occur during construction but not during operations. These residual adverse effects are expected to be reduced through mitigation and enhancement measures and ongoing engagement throughout the Project's operating life.

The CER noted that Foothills entered into agreements with potentially impacted Indigenous peoples to conduct Traditional Knowledge studies in relation to the Project and that not all of the expected studies are complete. Foothills stated that should Indigenous communities identify specific sites or features that have the potential to interact with Project activities; Foothills will engage in discussions with the appropriate Indigenous communities regarding the development of site-specific mitigation measures. The CER imposed Condition 11 (Outstanding Traditional Knowledge Studies) to ensure that Foothills incorporates any revisions necessitated by the studies or follow-up activities into the Environmental Protection Plan ("EPP") for the Project.

<u>Public Engagement</u>

The CER found that all potentially impacted landowners and stakeholders have been notified and given adequate opportunity to comment on the Project.

<u>Engineering Matters</u>

The CER noted Foothills' responsibility to ensure that the design, specifications, programs, engineering assessments, manuals, procedures, measures, and plans developed and implemented meet the *Canadian Energy Regulator Onshore Pipeline Regulations* requirements. This includes the Canadian Standards Association *Standard Z662 – Oil and Gas Pipeline Systems* ("*CSA Z662-19*").

The CER imposed Condition 2 of the approval conditions, requiring Foothills to construct and operate the Project in accordance with the information referred to in its application or as otherwise agreed to in its related submissions. The CER also imposed Conditions 1 and 4 of the approval conditions, requiring Foothills to file any technical specification updates for the pipeline listed in the Application concurrently with its LTO application. The CER limited technical specification updates to differences in pipe length, diameter, wall thickness, grade, or material that do not impact any other information provided in Foothills' application.

Partial LTO Exemptions

The CER was satisfied that, prior to installation, the relevant valves and tie-in assembly will be properly pressure-tested as required by the *CSA Z662-19*. The CER was further satisfied that the facility may be opened safely based on the facts presented: the nature of fluid (non-sour natural gas) reduces the potential consequences of a release, the expansion involves the replacement of interchangeable orifice-meter plates at a metering station, the maximum operating pressure is not being increased, and the company has not had recent compliance issues with hydro testing.

The CER, therefore, granted Foothills' request for an exemption from the LTO requirements for the tie-in assembly and the LTO requirements for the Kingsgate Border Meter Station. The CER reminded Foothills that it must apply for and receive LTO for the remaining facilities pursuant to s. 213 of the *CER Act* before placing them into operation.

Geotechnical Design

Foothills submitted that a field assessment (Phase II Assessment) was finalized during the assessment of the application, and it focused on the moderate and high-rated hazards from Phase I. Foothills submitted it would implement engineering measures, which may include implementation of engineered grade plans, appropriate depth of cover, use of heavy-wall pipe, and surface erosion controls, to mitigate the identified hazards.

The CER was satisfied that the mitigation measures for geohazards committed to by Foothills were appropriate.

Financial Matters

When considering the economic feasibility of the Project, the CER assesses the need for the Project and the likelihood of it being used at a reasonable level over its economic life.

Need for, and Alternatives to, the Project

Foothills stated that the Project is required to increase capacity on the Foothills System for November 1, 2023, to meet existing and incremental contract obligations to serve forecasted long-term aggregate natural gas transportation requirements on the Foothills BC System and that the Project is underpinned by contracts with a weighted average length of 30.5 years.

WEG raised concerns regarding the long-term need for the Project. WEG submitted that new and anticipated government policies to reduce greenhouse gas emissions and regulations would significantly impact the demand outlook for the Pacific Northwest and California region. WEG further stated that, for a capacity expansion on the Full Westpath to be useful to shippers, the capacity expansions are required to be coordinated across all three pipelines that comprise the Full Westpath. A final issue WEG raised was that contracting for additional capacity on either the Foothills BC System and/or the NOVA Gas Transmission Ltd. System is not useful, absent a further expansion of the Gas Transmission Northwest Pipeline System.

The CER determined that the Project is needed to meet existing and new contracts and positions the Foothills System to meet market demand. The CER acknowledged the significant demand expressed through the various open seasons, which this Project will not address, and that Foothills currently does not have future expansion plans. The CER noted that while companies require the flexibility to operate their pipeline systems efficiently and effectively, the CER may become concerned if the demand expressed by shippers continues to significantly exceed the capacity offered by a given project or suite of projects. Multiple projects that are applied for in the same temporal and geographic area place higher burdens on stakeholders for consultation and assessment of the projects and participating in the regulatory processes associated with those projects. The CER was of the view that this approach may not reflect regulatory efficiency.

Ability to Finance the Construction, Operation, and Abandonment of the Project

Foothills submitted that it considered ongoing law and policy development on carbon and climate change as required by the CER Filing Manual and noted that the drivers of the Project do not change as a result of climate change laws.

The CER was satisfied with Foothills' ability to finance the Project. The CER further found that Foothills had demonstrated that the net-zero action plan is unlikely to have a significant impact on the Project's economic feasibility.

Commercial Impacts

Foothills proposed to treat the costs of the Project on a rolled-in basis and apply the existing toll methodology of the Foothills BC System. The CER was satisfied that this would result in tolls that are just, reasonable, and not unjustly discriminatory. The CER also determined that the rolled-in tolling methodology remains appropriate and adheres to the principle of no acquired rights, which dictates that existing shippers and new shippers should equally pay for the increase in tolls.

Environmental Matters

Environment and Climate Change Canada's Response to Species at Risk Act Notification Letter

In response to the CER's *Species at Risk Act* ("*SARA*") notification letter, Environment and Climate Change Canada ("ECCC") advised that Foothills consult with ECCC for expertise and advice for the species at risk identified as potentially impacted by the Project. ECCC identified an additional 18 SARA-listed species and one species listed by the Committee on the Status of Endangered Wildlife in Canada that may potentially be affected by the Project.

The CER found that, with the implementation of Foothills' proposed mitigation measures and environmental protection procedures and the CER's imposed conditions, the Project is not likely to cause significant adverse environmental effects. The CER further found that the Project's contribution to existing and reasonably foreseeable cumulative effects will not be significant.

***NOVA Gas Transmission Ltd. for Firm Transmission Linked North Montney Service (FT-L (NM))* – CER Reasons for Decision RH-001-2021**

Just and Reasonable Rates - Economic Efficiency

In this decision, the CER considered an application filed by NOVA Gas Transmission Ltd. ("NGTL") for approval of a new service and related matters. The CER issued its decision on January 19, 2022, and in this letter announced its reasons for the decision. In its decision, the CER:

(a) denied the proposed Firm Transmission – Linked North Montney ("FT-L (NM)") Service and tolling methodology for the FT-L (NM) Service;

(b) denied the Rate Schedule FT-L (NM) Service that includes the proforma Service Agreement and proforma Schedule of Service under the NGTL Gas Transportation Tariff (the "Tariff"), and consequential amendments to the Table of Contents and General Terms and Conditions under the Tariff;

(c) approved the designation of the Willow Valley Interconnect ("WVI") as a Group 1 delivery point for the purpose of Firm Transportation – Delivery ("FT-D") Service and other delivery services in accordance with the rate design approved for the NGTL System, as may change from time to time; and

(d) did not affirm the tolling methodology approved in the RH-001-20191 Decision and Order TG-002-2020 for existing NGTL System services that utilize the North Montney Mainline ("NMML").

Background

NGTL requested approval of the proposed FT-L (NM) Service. The FT-L(NM) Service would provide linked receipt services from the NMML to the WVI delivery point, where the NGTL System will interconnect with the Coastal GasLink pipeline. NGTL and PETRONAS Energy Canada Ltd. ("PETRONAS") negotiated the FT-L (NM) Service to connect PETRONAS' gas supply on a short-haul path between designated receipt points along the NMML and the WVI delivery point.

NGTL further requested that the CER designate the WVI as a Group 1 delivery point for the purpose of FT-D service and other delivery services in accordance with the rate design approved for the NGTL System. As a Group 1 delivery point, the WVI delivery point would be subject to the Group 1 delivery point floor rate, which is the lesser of the East Gate and West Gate FT-D service rates.

In its application, NGTL acknowledged that the requirement of Condition 2 of Order TG-002-2020 would be triggered upon gas delivery at the WVI under either FT-L (NM) Service or FT-D service. NGTL requested an affirmation from the Commission that the NMML Tolling Methodology approved in the RH-001-2019 Decision for existing NGTL System services that utilize the NMML be maintained.

FT-L (NM) Service and Tolling Methodology

Prematurity

As an initial matter, the CER determined that NGTL did not prematurely file the application for FT-L (NM) Service. Phase 1 volumes are intended to begin shipping in 2024. The service tolling methodology is intended to apply to Phase 1 and 2 volumes.

Competition

In assessing the FT-L (NM) Service and tolling methodology, the CER considered whether competition was present in northeast British Columbia ("NEBC") and, if present, what role the existence of competition should play in determining if the FT-L (NM) Service would result in tolls that were just, reasonable, and not unjustly discriminatory. The CER also considered if the FT-L (NM) Service adhered to tolling principles, including cost causation and economic efficiency.

NGTL argued that in a competitive environment, the availability of competitive alternatives often eliminates the potential for abuse of market power by a pipeline. The CER disagreed with this argument. The CER found that while there is competition in NEBC, it is far from a perfectly competitive market. NGTL holds significant market power in NEBC. The existence of some competition does not eliminate the market power held by pipeline companies or the potential for abuse. Given the market power of NGTL and others in these circumstances, NEBC is not a context where competitive forces are sufficient to justify allowing the market to work with limited regulatory oversight. The CER accepted that the FT-L (NM) Service was created in response to a credible competitive alternative, as PETRONAS could ship volumes on either NGTL or Westcoast Energy Canada Ltd. ("Westcoast"). PETRONAS' stated that without the FT-L (NM) Service, it would have preferred the Westcoast alternative to shipping on NGTL based on the lower cost on Westcoast.

The CER found that it was appropriate for NGTL to develop a specialized service for liquid natural gas ("LNG") volumes when it was clear that its current service offerings were uncompetitive. However, the CER further found that these service offerings must still result in tolls that are just, reasonable, and not unjustly discriminatory. The CER held that, unlike previous cases, NGTL failed to meet its onus to establish that the FT-L (NM) Service was consistent with tolling principles, particularly the cost causation and economic efficiency principles.

Just and Reasonable Tolls

The CER held that the cost causation principle means that tolls should be, to the greatest extent possible, cost based and that users of a pipeline system should bear the financial responsibility for the costs caused by the transportation of their product through the pipeline without unjustified cross-subsidization by other rate payers.

(a) Cost Causation

The CER determined that tolls from the FT-L (NM), designed mainly to cover incremental costs, do not satisfy cost causation principles and that NGTL did not establish circumstances that justify a departure from the cost causation principle. The Commission was also of the view that the FT-L (NM) Service inappropriately shifts the burden of the risk of cost overruns onto shippers who are not using the FT-L (NM) Service.

The CER found that a toll specifically designed to recover incremental costs but not address existing system costs is a significant, and in this case unjustified, departure from the cost causation principle, particularly where the company has significant fixed costs. The proposed design creates the potential for inappropriate cross-subsidization of PETRONAS by existing shippers by not addressing existing system costs. A user of a pipeline system should bear financial responsibility for the costs caused by the transportation of their product through the pipeline. Pipelines, in general, have significant fixed costs that are recovered through tolls. If every service offered on a pipeline recovered only the incremental costs, then a pipeline would be unable to recover its large, fixed costs and, therefore, would not be financially viable.

NGTL argued that the FT-L (NM) Service would result in net benefits to shippers, as the incremental revenue from the FT-L (NM) Service would exceed costs. The CER found that the proposed net benefit is smaller and less certain than suggested by NGTL and that there is a high degree of uncertainty associated with the forecast benefit. Therefore, the CER was not persuaded that potential net benefits to shippers are certain or valuable enough to mitigate the risk of potential cross-subsidization of existing system costs resulting from the transfer of risk of cost overruns to other shippers inherent in the proposed tolling methodology.

(b) Economic Efficiency

The CER held that, in the context of regulated tolls, economic efficiency generally means that tolls should promote proper price signals, which will protect against over-investment and promote the efficient development and use of pipeline systems.

The CER found that the FT-L (NM) Service does not sufficiently promote efficient use of pipeline systems to justify a departure from the cost causation principle. When viewed as a package of Phase 1 and Phase 2 volumes, the FT-L (NM) Service does not primarily use underutilized capacity and thus will not maximize utilization on the NGTL System sufficiently to justify the departure from the cost causation principle. The CER was further not convinced that the proposed toll represented fair market value. The CER noted that the evidence required to demonstrate that the toll has been maximized and the toll is of fair market value is more than simply that the toll is the product of negotiations between two arm's length shippers.

Considering these findings, including NGTL's failure to adequately justify a departure from the cost causation principles, the CER determined the FT-L (NM) Service does not promote proper price signals and is overall not economically efficient.

(c) No Acquired Rights

The CER held that, generally, if tolls are otherwise just and reasonable, long-term transportation contracts do not violate the acquired rights principle simply by virtue of being long-term contracts, particularly if there is some indexing mechanism in place to ensure that the contracted shipper is subject to changing costs on the pipeline system.

The CER found that PETRONAS may not bear financial responsibility for the costs caused by the transportation of its gas under FT-L (NM) Service. This raises concerns regarding the acquired rights principle. Specifically, if PETRONAS is not paying for its present costs incurred, it is not paying for future costs incurred associated with the FT-L (NM) Service by virtue of its contracted use of the FT-L (NM) Service. This could be considered an acquired right.

(d) Conclusion Regarding Just and Reasonable Tolls.

The CER was not convinced that the FT-L (NM) Service results in just and reasonable tolls. The application was not premature, and it was appropriate for NGTL to develop a specialized service for LNG volumes in the face of competition. However, the FT-L (NM) Service did not satisfy cost causation or economic efficiency principles, and the FT-L (NM) Service could therefore not be approved.

Unjust Discrimination

The CER noted that unjust discrimination is prohibited by s. 235 of the *CER Act*. In the case of NGTL, all traffic is natural gas and, therefore, traffic of the same description, as required by s. 230 of the *CER Act*.

The CER denied the FT-L (NM) Service as NGTL failed to establish that the proposed tolls would be just and reasonable. The CER consequently found that there is no need for the CER to make a finding on FT-L (NM) Service with regards to unjust discrimination.

The CER, however, noted its concerns with the Optional Limited NOVA Inventory Transfer (“NIT”) Access (“OLNA”) feature of FT-L (NM) Service. The CER determined that, contrary to submissions from NGTL, the toll for OLNA is not similar to the Firm Transportation – Receipt (“FT-R”) toll. The OLNA toll is lower and, as a result, discriminatory. OLNA and FT-R Service both apply to traffic of the same description (gas), and both carry gas over the same route, from receipt points on the NMML to the NIT hub. The CER was not persuaded that the OLNA and FT-R Service are not substantially similar services.

<u>Willow Valley Interconnection Delivery Point</u>

The CER approved the designation as a Group 1 delivery point for the purpose of FT-D service and other delivery services as included in the rate design approved for the NGTL System. No party raised concerns regarding the proposed designation. Further, considering the potential benefits and adverse impacts on Canada’s natural gas markets, the CER found that new delivery points in the North Montney will increase the integration of that region to other markets and result in overall benefits to Western Canada Sedimentary Basin producers and others.

<u>Implications of Prior Orders</u>

NMML Tolling Methodology

The CER considered the impacts of the commencement of gas deliveries at the WVI delivery to determine if tolls would remain just and reasonable and not unjustly discriminatory. This included impacts to the findings in Decision RH-001-2019 regarding the extent of integration and utilization between the NMML and the rest of the NGTL System, qualitative benefits of the NMML to NGTL System shippers, and continued compliance with the cost causation and economic efficiency principles.

The CER determined that it did not have sufficient information to determine whether, upon commencement of gas deliveries at the WVI delivery point, that the existing NMML Tolling Methodology would continue to result in tolls that are just and reasonable and not unjustly discriminatory. The CER recognized the commercial uncertainty associated with delay but considered it prudent and reasonable to delay this determination pending receipt of better information that will be available in the future. The CER, therefore, denied NGTL’s request without prejudice.