REGULATORY LAW CHAMBERS

ISSUE: MARCH 2024 DECISIONS

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 COURT OF APPEAL

***Enmax Corporation v Independent System Operator (Alberta Electric System Operator),* 2024 ABCA 83**
Electricity - Appeal

Application

This was an appeal of a chambers judge decision ("Decision") dismissing the originating application of ENMAX Corporation, ENMAX Energy Corporation and Calgary Energy Centre No. 2 Inc. (collectively, "Appellants" of "ENMAX") for an order directing the respondent, the Alberta Electric System Operator ("AESO"), to pay the Appellants a credit of $8,343,537.15 owing to two partnerships, which are dissolved.

Decision

The Alberta Court of Appeal ("ABCA") applied the correctness standard and held that the chambers judge's conclusion that *res judicata* applied in this matter was correct and that no appellate intervention was warranted. The ABCA dismissed the appeal.

Pertinent Issues

ENMAX argued that the chambers judge erred in reaching the Decision by: misstating and misapplying the legal test for *res judicata*; misinterpreting or failing to properly analyze the Alberta Utilities Commission ("AUC") Decision 790-D06-2017 ("Module C Decision"); ignoring and failing to give effect to the Assignment, Assumption and Novation Agreement between Calpine (as assignor), Calgary Energy Centre No. 1 Inc (as assignee) and the AESO ("AA&N Agreement"); and ignoring or failing to properly consider the AUC Decision 27048-D01-2022 ("Guidance Decision").

In 2005, the AESO implemented a line loss rule for calculating transmission loss factors ("2005 Line Loss Rule"). On April 16, 2014 in Decision 2014-110, the AUC determined that the 2005 Line Loss Rule was unlawful, which meant that the AUC had to retroactively re-calculate those transmission line loss charges and credits that had been unlawfully imposed and that it had to administer adjusted line loss charges and credits.

In 2007, the interests of Calpine Energy Services Canada Partnership and Calpine Power LP (collectively, "Calpine") in supply transmission service agreements relative to the Calgary Energy Centre No. 2 Inc. (the "Facility") were formally transferred to the Calgary Energy Centre No. 1 Inc. via the AA&N Agreement. In December 2007, Calpine was dissolved. In 2008, ENMAX acquired the shares of Calgary Energy Centre Holdings Inc., which, in turn, held all the shares of the Facility. The Facility was the successor by amalgamation of the Calgary Energy Centre No. 1 Inc.

In the Module C Decision, the AUC held that invoices for final rates to replace interim rates must be issued to the original cost causers and cost savers, not only because they were competitors of each other, but because they were the parties unjustly and unduly advantaged or disadvantaged by the unlawful interim rates.

In furtherance of the Module C Decision, the AESO calculated a total refund of $11,349,353.36 owing in relation to the Facility. Of that total, it refunded $3,055,816.20 to ENMAX as the party that paid invoices from the AESO in respect of the Facility for the period January 1 to July 31, 2007, in accordance with an agreement between ENMAX and Calpine. The AESO attempted to refund the balance to Calpine as the holder of the supply transmission service agreements between February 1 to December 31, 2006, but Calpine had been dissolved.

ENMAX proceeded with a Court of King's Bench application for an order directing the AESO to pay the full amount of the credit to ENMAX or a declaration that ENMAX is the lawful recipient and assignee of the credit under agreements with the previous owner of the Facility. ENMAX's application was dismissed on the grounds of *res judicata* (issue estoppel). The chambers judge found that the AUC's Module C Decision had determined that only the "original cost causers and cost savers" were entitled to receive the credit amount, which decision was final since it was not appealed.

To the extent the chambers judge found that, between the AESO and ENMAX, the Module C Decision determined the legal effect of the AA&N Agreement on which ENMAX relied to claim the full credit amount, the ABCA agreed. Regardless of any rights ENMAX may have or have had against the previous owner of the Facility in respect of the credit in question, it did not have a right to claim the credit directly from the AESO. While the ABCA recognized that the combination of the Module C Decision and

Calpine's dissolution in 2007 created a practical problem for ENMAX, this was not a basis on which to refuse to apply the doctrine of *res judicata*. Doing so would undermine the essence of the Module C Decision. The ABCA upheld the decision of the chambers judge concluding that the Module C Decision clearly determined the rights and obligations between the AESO, on the one hand, and assignor and assignees of the AA&N Agreement, on the other.

ALBERTA ENERGY REGULATOR

Pilot for Reclaiming Peatlands, AER Bulletin 2024-04

Oil and Gas – Land Reclamation

On December 14, 2023, Alberta Environment and Protected Areas ("AEPA") released the *Interim directive: pilot for reclaiming peatlands - decision framework and support tools for reclaiming well sites and access roads on public lands (Land Policy, 2023, No.3)*, regarding a pilot program for reclaiming peatlands and a new process for approving changes in land use dispositions.

Under the AEPA's current policy, the standard practice is to return oil and gas dispositions on public land to their pre-disturbance land use, which involves removing any imported materials from the site. In some cases, disposition holders may apply to AEPA for permission to leave the land in its current state and not require that it be returned to its pre-disturbance use. If approved, AEPA issues an approval for the imported materials to remain in place and provides it to the Alberta Energy Regulator ("AER") as part of the reclamation certificate application package.

This pilot streamlines the reclamation process by transferring regulatory authority to the AER to approve requests for land use changes for oil and gas dispositions.

The pilot only applies to oil and gas well sites, and access roads on public land that are:

- not associated with an *Environmental Protection and Enhancement Act* approval; and

- are entirely outside the boundary of a caribou range.

The AER will accept submissions for the pilot program until July 31, 2025, which can be submitted as a reclamation certificate variance through OneStop. The requests must be approved before a reclamation certificate application is submitted.

Site Reduction Reclamation Certificate Pilot, AER Bulletin 2024-05

Facilities – Partial Reclamation

In December 2023, Alberta Environment and Protected Areas ("AEPA") announced the *Interim directive: pilot for site reductions on well sites (Land Policy, 2023, No.2)*, regarding a pilot program for certifying that an unused portion of a well site meets government reclamation standards.

Currently, licensees may only apply to the AER for a reclamation certificate once the well is listed as abandoned and the entire site is remediated and reclaimed to equivalent land use capability.

This pilot allows licensees to apply for a reclamation certificate for the unused portion of a well site that meets equivalent land use capability even though the well and portion of the well site are still active. The active portion of the well site will require a reclamation certificate at the end of its life.

As noted in the interim directive, licensees must obtain signed consent from landowners agreeing to participate in the pilot. Licensees must demonstrate that they have consulted with the landowners. Landowners must sign a landowner consent document indicating their agreement to participate in the pilot and that they understand the potential implications of participating. Landowner participation in the pilot is voluntary. The licensee must include the signed landowner consent document with the reclamation certificate application.

New and Enhanced Functionality Moving to OneStop, AER Bulletin 2024-06

Applications -Process

The AER announced new functionality and enhancements to its OneStop platform. The AER will post notice and schedule a system outage to implement these changes. The changes relate to the following legislation and policies.

Water Act

For *Water Act* approvals for borrow pit activities, applicants will have the option to identify whether the wetland policy applies to their associated in situ or mining projects.

Public Lands Act

The AER added enhancement to:

- plan replacements that will allow disposition holders to disconnect public land dispositions; and
- cancellations that will enable OneStop to automatically generate cancellations for the following public land dispositions:
  - dispositions not entered within the five-year stage gate period as per approval conditions; and
  - dispositions being cancelled through the reclamation certificate process.

Pilot for Site Reductions on Well Sites

The AER made an enhancement allowing it to issue a reclamation certificate for sites that meet the eligibility criteria set out by the Government of Alberta's pilot program for lease reductions.

Conditional Adjustment of Reclamation Liability

The AER announced that in April 2024, it will release a new Conditional Adjustment of Reclamation Liability submission type to allow for conditional adjustments to the reclamation liability estimate used in the AER's liability management programs.

Pilot for Reclaiming Peatlands

On February 7, 2024, the Reclamation Certificate Variance submission was enhanced to support the Government of Alberta's interim directive for reclaiming peatlands.

***2024/25 AER Administration Fees (Industry Levy),* AER Bulletin 2024-07**

Oil and Gas – Revenue Requirement

For 2024/25, the Government of Alberta approved a revenue requirement of $225.2 million to support the AER's operations. The AER published the administration fees allocated according to the industry sectors based on the AER's operational requirements for specific sectors.

2024/25 Administration Fees (Industry Levy)

The AER announced the following industry levy amounts for 2024/25 by sector:

Sector	**2024 ($000)**	**2023 ($000)**
Oil and Gas	155 397	154 346
Oil Sands	43 720	43 245
Coal	8 064	8 718
Pipelines	12 276	7 479
Facilities (*Directive 056*)	5 158	3 218
Facilities (*Directive 023*)	631	413
Total	225 246	217 419

Oil and Gas Sector

The administration fee in the conventional oil and gas sector is based on individual well production of oil and bitumen or gas and the number of inactive, in service, and production wells for 2023. Wells are classified in the classes set out in the *Alberta Energy Regulator Administration Fees Rules* ("*AFR*"). An adjustment factor is applied to ensure that the administration fee collected for each sector satisfies the AER's revenue requirement. For the oil and gas sector, the AER will apply an adjustment factor of 3.890075. The fee is allocated as follows:

Fee Class	**Min. production (m^3/yr)**	**Max. production (m^3/yr)**	**Base fee 2024/25**
0	Inactive wells	Not Applicable	$42.00
1	Service wells	Not Applicable	$50.00
2	0.01	300	$42.00
3	300.1	600	$102.00
4	600.1	1 200	$240.00
5	1 200.1	2 000	$460.00
6	2 000.1	4 000	$1 040.00
7	4 000.1	6 000	$1 740.00
8	6 000.1	8 000	$2 560.00
9	8 000. 1	10 000	$3 500.00
10	10	>	$3 800.00

Alberta Upstream Petroleum Research Fund

The Canadian Association of Petroleum Producers ("CAPP") and the Explorers and Producers Association of Canada ("EPAC") requested that the AER's administration fee process be used to collect $5.3 million to fund the Alberta Upstream Petroleum Research Fund ("AUPRF") in 2024. The AER granted the request and included an amount for this funding in the oil and gas well administration fee invoices, the payment of which is voluntary and not subject to penalties.

Oil Sands Sector

The fee for this sector is levied in five categories based on operating information for the 2023 year. One operator may have activities in more than one category. The fee is subject to an adjustment factor and is allocated as follows:

Category	Allocation ($000)	Adjustment factor
Primary ongoing	5 312	2.777591
Thermal ongoing	14 489	2.594022
Thermal growth	2 488	10.609170
Mining ongoing	1 9940	2.898922
Mining growth	1 491	13.576640
Total	**43 720**	

Coal Sector

The administration fee for coal is based on each mine's share of total production volumes for 2023, and is set at $0.723644 per ton of coal, as specified in the *AFR.*

Pipelines Sector

The administration fee for pipelines is based on the segments of a pipeline in each class as of Dec 31, 2023. Pipelines subject to an administration fee are classified by pipe diameter with an adjustment factor of 2.234722.

Class	Diameter (mm)	Base fee ($)
A	<168.3	50.00
A (Discontinued)		25.00
B	≥ 168.3 and <609.6	60.00
B (Discontinued)		30.00
C	≥609.6	200.00
C (Disontinued)		100.00

Facilities (Directive 056) – Gas Plants

The administration fees are levied to gas plant facilities with an inlet rate greater than or equal to ten million cubic meters per day as of Dec 31, 2023, and an active, new or unknown activity status. The rate is set at $7.741826 for every thousand cubic meters per day and is applied based on the individual facility inlet rate, as specified in the *AFR*.

Facilities (Directive 023) – Processing Plants

The administration fees are levied to processing plant facilities approved under the *Oil Sands Conservation Act* with an operating status as of Dec 31, 2023. The rate is set at $9.248995 for each cubic meter per day and is applied based on the individual facility inlet rate, as specified in the *AFR*.

Payment

Payment of all invoices is required by May 1, 2024, regardless of whether an appeal has been filed. Following a decision on the appeal, adjustments will be applied, as needed.

***2024/25 Orphan Fund Levy/LLR and OWL Programs,* AER Bulletin 2024-08**

Oil and Gas – Abandonment

The Government of Alberta approved a levy of $135 million to fund the Orphan Well Association's ("OWA") operating budget for the fiscal year 2024/25. As a result, the AER prescribed an orphan fund levy of $135 million. The AER will allocate the orphan fund levy among licensees and approval holders included within the Licensee Liability Rating ("LLR") and Oilfield Waste Liability ("OWL") programs based on the April 2024 liability management rating assessment.

All orphan fund levy invoices must be paid in full by the licensee or approval holder and received by the AER by May 10, 2024. Failure to pay the full invoiced amount by May 10, 2024, will result in a penalty of 20 per cent of the original invoiced amount assessed to the licensee or approval holder. The notice of payment may be appealed, however, even if an appeal is filed, payment in full of the original invoiced amount is required by May 10, 2024, subject to a refund if the appeal is successful.

ALBERTA UTILITIES COMMISSION

AUC Updates to the Hydro and Electric Energy Regulation, **AUC Bulletin 2024-04**

Power - Law

On March 6, the Alberta Utilities Commission ("AUC") made updates to the *Hydro and Electric Energy Regulation* ("*HEER*") to align it with the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act* ("*Amendment Act*"). The updated regulation, made by the AUC through Order 2024-001, came into force at the same time as the *Amendment Act*, which was March 6, 2024.

The updated regulation aims to improve efficiency and reduce regulatory burden by eliminating outdated filing requirements. The regulation includes new requirements for energy storage facilities and clarifies the approval process for alterations to existing facilities and certain types of connection applications. It also provides for exclusions from certain sections of the *Hydro and Electric Energy Act* ("*HEEA*") with respect to small power plants and isolated generating units.

Amendments to Rule 027, **AUC Bulletin 2024-05**

Power - Law

The AUC amended *Rule 027: Specified Penalties for Contravention of Reliability Standards* ("*Rule 027*") to include the reliability standard PER-006-AB-1 (R1), assigning this standard a penalty category 2. The AUC determined that this change to *Rule 027* was administrative in nature, which did not require a consultation process.

AUC Updates to Rule 007, AUC Bulletin 2024-06

Facilities – Applications

The AUC updated *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* ("*Rule 007*") to align it with the *Electricity Statutes (Modernizing Alberta's Electricity Grid) Amendment Act* and the amended *Hydro and Electric Energy Regulation*.

Updates to *Rule 007* integrate the information requirements for energy storage facilities with distinct types of ownership. Similar to other types of electric facility applications, information required for amending, decommissioning and salvaging, cancelling or extending the construction completion date of an energy storage facility was added. The updated *Rule 007* also provides exemptions from filing an application for small power plants, small energy storage facilities and isolated generating units, if certain criteria are met.

Alberta Electric System Operator Approval of Amended Alberta Reliability Standard COM-001-AB-3 and COM-002-AB-4, **AUC Decision 28904-D01-2024**

Electricity – Rules

<u>Application</u>

The Alberta Electric System Operator ("AESO") forwarded proposed changes to the Alberta reliability standards COM-001-AB-3 (Communications) and COM-002-AB-4 (Operating Personnel Communications Protocol) to the AUC for review with its recommendation that the AUC approve the amended reliability standards.

<u>Decision</u>

Noting the lack of objections and considering the recommendation from the AESO, the AUC approved the amended standards.

<u>Pertinent Issues</u>

The AESO submitted that the changes were comprised of corrections to typographical errors in the final versions of the standards approved by the AUC in Decision 27990-D01-2023. The AESO stated that these errors were a result of oversight in submitting final documentation and that they do not impact the content that was subject to prior consultation and approval by the AUC.

Accordingly, pursuant to s 19(6) of the *Transmission Regulation*, and based on the recommendation by the AESO, the AUC approved the amended COM-001-AB-3 and COM-002-AB-4 standards, effective April 1, 2024.

***ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. 2024-2026 General Rate Application Negotiated Settlement Agreement and Excluded Matters,* AUC Decision 28369-D01-2024**

Gas – Rates

<u>Application</u>

ATCO Pipelines ("ATCO") filed its general rate application ("GRA") for 2024-2026, seeking AUC approval of the amount of revenue it requires to provide safe and reliable gas transmission service for the 2024, 2025 and 2026 test years. ATCO requested the following approvals:

- Revenue requirements of approximately $358.62 million for 2024, $371.37 million for 2025 and $388.13 million for 2026;
- Compliance with the AUC directions;
- The continued use of certain deferral and reserve accounts, and the creation of the Information Technology ("IT") Transition Temporary deferral account, and the discontinuation of the Pandemic Cost deferral account; and
- Establishing the NOVA Gas Transmission Ltd. ("NGTL") identified growth deferral account ("Deferral Account") and a zero-dollar placeholder for construction work in progress ("CWIP") in rate base for the Yellowhead Mainline Project ("Yellowhead").

<u>Decision</u>

The AUC approved the negotiated settlement agreement ("NSA") regarding the GRA and denied the matters excluded from the negotiated settlement process ("NSP"), namely the Deferral Account and CWIP treatment of Yellowhead (collectively, "Excluded Matters"). Yellowhead is a proposed 200 km pipeline expected to cost up to $2.5 billion. As a result of the denial of the Excluded Matters, the GRA test period included 2024 and 2025 and excluded 2026. The approved revenue requirement for 2024 was $362.852 million, and for 2025 was $374.488 million.

<u>Pertinent Issues</u>

The AUC approved ATCO's request to enter into the NSP and explore the possibility of reaching the NSA. The AUC excluded from the NSP ATCO's requests to establish the Deferral Account and include CWIP in rate base for Yellowhead.

ATCO and the parties who participated in the NSP reached the NSA and agreed that, if the AUC approved the Excluded Matters, the test period would be three years, and if the AUC denied the Excluded Matters, the test period would be two years.

<u>**AUC Findings**</u>

Deferral Account

The AUC considers the following factors when evaluating a request for a deferral account: (i) materiality of the forecast amount; (ii) uncertainty regarding accuracy and ability to forecast the amount; (iii) factors affecting the forecasts being beyond the utility's control; and (iv) whether or not the utility is typically at risk for the forecast amount. In addition, the AUC considers the symmetry factor, which requires symmetry between costs and benefits for both the company and its customers. These factors, however, are not exhaustive and meeting these factors does not necessarily mean that a deferral account will be automatically granted.

The AUC found that information concerning the Deferral Account was materially deficient and that additional details regarding the scope, timing and forecast costs of Yellowhead will be filed in a future needs application. As a result, the AUC found the request for the Deferral Account premature. The AUC also found the request for the Deferral Account inconsistent with the expected evolution of the working dynamics of the Alberta Integrated System. The onus rests with ATCO to justify its forecasts, and integration should not act as an impediment to properly scrutinize proposed capital projects that will ultimately go into rate base.

If a particular project, such as Yellowhead, was uncertain to the extent that ATCO could not justifiably include it in its forecast for the test period to allow proper testing, the AUC was not persuaded that it was symmetrical and that it was in the public interest to approve a deferral account for that project. ATCO stated that if Yellowhead were cancelled, it could recover costs related to it, such as operating and maintenance expenses, in its next GRA. As a result, the AUC found that the Deferral Account and the related uncertainty associated with the project and its costs shifted a disproportionate amount of risk onto ratepayers.

CWIP

The AUC found that ATCO provided a cursory level of information on its credit rating metrics concerns regarding its request for a zero-dollar placeholder for CWIP in rate base. Absent more information on the project, such as a business case, tangible annual cost forecasts, and related credit rating metric impacts, the AUC considered the information on the record insufficient to warrant a zero-dollar placeholder for CWIP in rate base for Yellowhead.

Negotiated Settlement

When assessing negotiated settlements that reach a unanimous agreement, the AUC applies a test that requires consideration of three factors: (i) was the negotiation process fair, including with respect to notice and the conduct of the process itself; (ii) will the settlement result in just and reasonable rates; and (iii) are any of the settlement provisions, individually or collectively, patently against the public interest or contrary to law? In performing this assessment, the AUC reviews the individual provisions of the NSA and the NSA as a whole.

NSP

The NSP and NSA do not replace a full and informed review by the AUC regarding what is in the public interest. Because ATCO requested and received AUC approval to negotiate a settlement and applied for approval of the executed NSA in its entirety, the AUC assumed the NSA satisfied ATCO's interests and assessed the NSA from the ratepayers' point of view only.

The AUC was satisfied that parties had the opportunity to participate meaningfully in the NSP, that the negotiations were conducted in an open and fair manner, and that ATCO provided adequate notice to parties interested in participating in the negotiations.

NSA

In conducting the public interest assessment, the AUC considered each element of the NSA and the NSA as a whole. The AUC considered the public interest from the perspective of ratepayers by reviewing each of the material provisions of the NSA to determine if any of these provisions appear to be unusual, contrary to accepted regulatory practices or could result in undue rate effects, service concerns, preferences or other concerns in future rate applications. The AUC also considered whether the effect of the NSA would lead to rates, and terms and conditions of service that are just and reasonable.

Based on the assessment of the provisions of the NSA, along with the detailed analysis of the application and information request ("IR") responses, the AUC found that the NSA, taken as a whole, was not patently against the public interest or contrary to law. The AUC also found that the NSA resulted in rates, and terms and conditions that are just and reasonable. Accordingly, the AUC approved the NSA as filed, applicable to the 2024 and 2025 test years.

The AUC also directed ATCO to provide, as a post-disposition filing, updated schedules reflecting the removal of the 2026 test year and the zero-dollar placeholders for expenditures related to Yellowhead, within 30 days of the issuance of the decision.

Compliance with the AUC Directions

In its application, ATCO also responded to five directions from *Decision 25663-D01-2021*, one direction from *Decision 26443-D01-2021*, three directions from *Decision 23793-D01-2019* and one direction from *Decision 22011-D01-2017*. The AUC determined that ATCO complied with the directions and that no further action was required, reminding ATCO that it must still comply with all directions that require ATCO to provide information in future GRA filings.

EMCOR Utility (2035570 Alberta Ltd.) 2023-2027 General Rate Application, **AUC Decision 28055-D02-2024**

Water – Review and Variance

Application

EMCOR Utility (2035570 Alberta Ltd.) ("EMCOR") applied for approval of its general rate application ("GRA") regarding its potable water system for the 2023-2027 test years.

Decision

The AUC approved the GRA, as follows:

- the final revenue requirements for the periods June 7, 2023, to February 29, 2024; March 1, 2024, to February 28, 2025; March 1, 2025, to February 28, 2026; and March 1, 2026, to February 28, 2027;

- final rates effective June 7, 2023, March 1, 2024, March 1, 2025, and March 1, 2026;
- the recovery of depreciation and return on rate base as part of its revenue requirements, as a proxy for CME Holdings Ltd.; and
- terms and conditions of service, contingent upon certain matters EMCOR is required to undertake.

The AUC also directed EMCOR to file an application to true up its interim rates to final rates for the period June 7, 2023, to March 31, 2024.

Pertinent Issues

The AUC considered EMCOR's application in two parts. In part one, in Decision 28055-D01-2023, the AUC found that EMCOR's potable water system met the definition of a public utility, and that EMCOR was the owner, approving interim rates for the supply and distribution of potable water, effective June 7, 2023, until the final rates were determined.

In this decision, the AUC determined the final rates and approved the terms and conditions ("T&Cs") of EMCOR's potable water service. EMCOR did not seek approval of its rates for recycled water, fire protection, irrigation water, or stormwater collection systems, arguing that these systems are not public utilities.

Under the *Public Utilities Act* ("*PUA*"), the AUC fixes just and reasonable rates of the owner of a public utility by applying cost-of-service regulation for investor-owned water utilities. Under this methodology, a regulated utility is allowed to charge rates sufficient to cover its operations and maintenance ("O&M") costs and provide a fair rate of return on and return of capital. The first step of this methodology is establishing the forecast revenue requirement to serve utility customers, which includes consideration of O&M costs, depreciation, taxes and an allowed rate of return on rate base. The second step allocates the revenue requirement to customer classes and establishes rates that are necessary to recover the forecast revenue requirement. This decision addressed both steps concurrently.

The AUC is required to approve forecast costs for the safe and reliable operation of EMCOR's potable water system, while ensuring just and reasonable rates for the service received by its customers.

Rates

1. Test Period and Associated Rates

The AUC approved the final revenue requirements for the following periods: June 7, 2023, to February 29, 2024; March 1, 2024, to February 28, 2025; March 1, 2025, to February 28, 2026; and March 1, 2026, to February 28, 2027. The AUC approved the final rates effective June 7, 2023, March 1, 2024, March 1, 2025, and March 1, 2026.

2. Eligibility for Return on Rate Base and Depreciation

A regulated utility is permitted to earn a return on and a return of the money invested in rate base. The return on the money invested makes up the return on debt and return on equity components of the revenue requirement. The return of the money invested makes up the depreciation component of the revenue requirement.

EMCOR indicated that CME Holdings Ltd. ("CME"), the parent company of EMCOR that owns 100 percent of EMCOR, built and paid for all of the utility system infrastructure subsequently transferring it to EMCOR, for a consideration of one dollar and Class A common shares. While EMCOR, by itself, did not invest anything in its rate base, CME did. Accordingly, the AUC permitted EMCOR to recover depreciation and return on rate base as a proxy for CME's investment. While the AUC considered this fair, it noted that, if EMCOR issues any shares to a party other than CME or if CME sells, transfers or disposes of any or all of its shares in EMCOR, the proxy recovery of depreciation and return on rate base will no longer be permitted.

3. Rate Base and Return on Rate Base

Since this was the first potable water rates application filed by EMCOR, the AUC must approve the rate base figures on February 29, 2024, February 28, 2025, February 28, 2026, and February 28, 2027. The AUC calculated opening and closing rate base on a fiscal year basis because the information submitted by EMCOR was on a fiscal year basis. Since the first bill issued for potable water service was for the consumption period from February 15, 2018, to May 31, 2020, depreciation of the potable water system begins with the first date of commercial operation. As a result, in its calculations of the opening rate base for March 1, 2023, the AUC included accumulated depreciation for the period February 15, 2018, to February 28, 2023.

The AUC concluded that no amounts for contributions should be included based on EMCOR's submission that no contributions were collected from customers to help finance the capital cost of the potable water system, and that there are no requirements in its franchise agreement with the Rocky View County with respect to a contribution factor, no-cost capital, and rate base.

The AUC excluded any costs for working capital from the approved rate base. The AUC was of the view that to add working capital to rate base it must consider both the revenue side and the expense side of the utility's operations. EMCOR's assessment of the reasonableness of the 45-day lead lag only discussed the revenue side and not the expense side, even though the AUC asked EMCOR to explain the reasonableness based on the billing cycle, payment deadlines, payment received from customers and when payments are made to suppliers.

The AUC approved the deemed capital ratio of 60 percent debt and 40 percent equity as being consistent with AUC-approved deemed capital structure for two other water utilities identified by EMCOR. The AUC determined that the 40 per cent deemed equity reflects the fact that EMCOR has more business and investor risk than the utilities that are included in the generic cost of capital proceedings, which have lower deemed equity ratio.

The AUC approved the forecast return on equity of 9.28 per cent requested by EMCOR for the fiscal years ending February 29, 2024, February 28, 2025, February 28, 2026, and February 28, 2027, which is the same as the latest return on equity percentage approved by the AUC in Decision 28585-D01-2023.

The AUC approved the forecast return on debt of 6.45 per cent requested by EMCOR, accepting EMCOR's explanation that CME finances capital expansion and operations with a line of credit, which has a current interest rate of 6.45 per cent.

4. Reduction to Return on Rate Base and Depreciation for Unused Capacity

One principle of utility rate setting is that customers should only pay for the portion of the utility that is used to provide utility service to the public.

The developed acres forecast, which is part of the fixed charge, and the water usage forecast, which is a charge for water usage, when compared to the design capacity of the potable water system, indicate that the system is not fully utilized to provide utility service to the public. The design capacity of the potable water system was sized to accommodate the entire development, which is incomplete. The AUC was of the view that it was fair for EMCOR to recover depreciation and return on rate base as part of its revenue requirement and that it was also fair for current customers to not be required to pay for the full share of the depreciation and return on rate base because the system is not fully utilized.

Therefore, it was necessary for the AUC to include depreciation and return on rate base in the revenue requirement that reflects only the portion of the total system used to provide utility service to the public. The AUC held that depreciation and return on rate base attributable to the unused portion of the total system will be borne by the shareholder of EMCOR.

5. Water Waste Haulage Forecast

The AUC did not accept the water waste haulage expense forecast initially submitted by EMCOR. The wastewater haulage expense was the largest of EMCOR's forecast O&M expenses. The AUC had concerns with the wastewater haulage forecasting model. When comparing the actual expense for wastewater haulage with EMCOR's forecast for those same periods, the forecast appeared low. The forecast also did not include an assumption for inflation in haulage costs, suggesting under-forecasting. Finally, the volume per truckload assumption did not correspond to the data provided in the invoices.

Following clarifications and further information from EMCOR, the AUC set the revenue requirement for the wastewater haulage expense, which represented a cumulative addition of $13,878 for the period from June 7, 2023, to February 28, 2027.

6. Final Revenue Requirement and Rates and Projected Revenues Compared to AUC-Approved Revenue Requirements

Because of the reductions made by the AUC to the depreciation expense and return on rate base amounts to reflect the unused capacity of the water system, the AUC approved lower than applied-for revenue requirements, as follows:

- $127,613 for the period June 7, 2023, to February 29, 2024;
- $192,131 for the fiscal year March 1, 2024, to February 28, 2025;
- $202,163 for the fiscal year March 1, 2025, to February 28, 2026; and
- $205,668 for the fiscal year March 1, 2026, to February 28, 2027.

7. Compliance with previous AUC Direction

The AUC found that EMCOR complied with the direction from paragraph 25 of Decision 23256-D01-2018, which required EMCOR to ensure that the water licence was issued or transferred in its name as soon as feasible, including filing a copy with the AUC once it was obtained.

8. Terms and Conditions of Service

EMCOR also sought approval of the T&Cs, which regulate its potable water services and outline the rules, obligations and terms that govern the provision of utility services between EMCOR and its customers.

The AUC was satisfied that the T&Cs contributed to ensuring that the rates approved in this decision were just and reasonable and that they reflected the AUC's consideration of all relevant factors in this proceeding by balancing the interests of both the utility and customers. The AUC directed EMCOR to correct certain inconsistencies in the T&Cs and approved administrative charges in the amount of $50 for returned payment, call back or late payment, as applicable.

9. True-up of Interim and Final Rates

The AUC approved interim rates in Decision 28055-D01-2023, effective June 7, 2023, approving the final rates in this decision. Consequently, the AUC directed EMCOR to file an application with a true-up proposal. The application must include details for the calculated revenue differences and the proposal for collection, including the period over which the collection would take place.

10. Recycled Water, Fire Protection, Irrigation Water and Stormwater Collection Systems

EMCOR only sought approval of its potable water rates, and not the rates for recycled water, fire protection, irrigation water, or stormwater collection systems ("Systems"). The AUC decided not to make a finding in this decision regarding whether the Systems are a "public utility" under the *Public Utilities Act* ("*PUA*"). The AUC emphasized that if it receives an application or complaint, or otherwise becomes aware of any potential mischief or other compelling concern in relation to the Systems, it will make a determination on whether the Systems are public utilities, as defined in the *PUA*.

The AUC provided the following commentary to assist EMCOR and its customers in determining whether they may file an application or complaint in relation to the Systems.

The AUC disagreed with EMCOR's submissions regarding why the Systems should not be considered public utilities. The AUC found that non-potable water is not excluded from the meaning of "water" in the definition of "public utility" in the *PUA.* There is no legislative definition of "water" in the *PUA* and the ordinary meaning of water is general, broad and includes potable and non-potable water. The AUC gave significant weight to the ordinary meaning of "water" when interpreting these provisions.

The AUC also noted that this interpretation was consistent with its precedent. It further stated that wastewater, if treated, may no longer carry attributes that would ordinarily classify it as wastewater and that it may be used to provide non-wastewater services even if it remains non-potable.

Contrary to EMCOR's arguments, the AUC noted that customers do not need to have unrestricted access to the water on demand, and that they do not need to possess the water to the exclusion of others, to allow the assumption of a public utility.

***Salt Box Coulee Water Supply Company Ltd. Decision on Preliminary Question Application for Review of Decision 28021-D02-2024 and Order 28021-D03-2024,* AUC Decision 28021-D04-2024**

Water – Review and Variance

Application

Salt Box Coulee Water Supply Company Ltd. ("Salt Box") applied to the AUC for a review of Decision 28021-D02-2024 (the "Decision") and Order 28021-D03-2024 (the "Order").

The Decision denied a negotiated settlement agreement ("NSA") application filed by the AUC enforcement staff ("Enforcement Staff") regarding penalties for contraventions established in Decision 28021-D01-2024, following Salt Box's non-compliance with the NSA's agreed-upon terms.

The Order directed Salt Box to file certain documents with the AUC relating to the utility's financial position.

Decision

The AUC denied the review application because the Decision and Order were interlocutory decisions and Salt Box failed to persuade the AUC that special circumstances existed that wound warrant granting the review.

Pertinent Issues

Background

Proceeding 28021 was convened to consider an application from Enforcement Staff alleging that Salt Box committed two contraventions of a prior AUC decision. In Decision 28021-D01-2023, the AUC found that Salt Box committed the following contraventions:

(a) Failing to file audited financial statements contrary to the AUC's direction in Decision 24295-D02-2020 ("Contravention 1"); and

(b) Charging monthly fees and rate riders to unconnected lot owners contrary to the rates, and terms and conditions of service approved in Decision 24295-D02-2020 ("Contravention 2").

On October 20, 2023, Salt Box and Enforcement Staff proposed the NSA to address the contraventions established in phase one of the enforcement proceeding.

In considering the NSA, the AUC issued information requests ("IR") to Salt Box. In the IR responses, Salt Box stated that it could not meet the terms of the NSA despite agreeing to them.

In January 2024, after becoming aware that Salt Box had been struck from the Alberta Corporate Registry for failure to file annual returns, the AUC issued the Decision and Order. The Decision denied the NSA application. The AUC found that approval of the NSA would not be in the public interest, because it was clear that Salt Box was unwilling or unable to adhere to the terms to which it had agreed.

Salt Box Submissions

In the review application, Salt Box raised concerns about the stress it encountered, including in relation to obtaining a financial audit. Salt Box stated that quotes for a financial audit were significantly higher than the rider that was previously approved by the AUC for this purpose. Salt Box suggested that the AUC's initial direction to require an audit in 2020 was based on incorrect information.

Salt Box asserted that the direction in the Order to provide six years of detailed information on all aspects of its operations, financial and otherwise, in a matter of two weeks was not reasonable or possible. The review application also set out concerns about financial approvals of the AUC, including in relation to utility system upgrades that were mandated by Alberta Environment and Protected Areas, as well as depreciation funding and return on capital.

AUC Findings

The AUC stated that a threshold issue was whether the Decision and Order were eligible for review. Central to this determination was whether the Decision and Order constituted a final determination of Salt Box's substantive rights or whether the Decision and Order were interlocutory in nature.

The AUC determined that the Decision and Order did not determine, in whole or in part, any substantive rights of Salt Box or any other parties' rights. Rather, the Decision and Order functioned as procedural interlocutory directions to support the AUC in resolving this enforcement proceeding. As a result, the AUC found them to be interlocutory, rather than final.

Consistent with decisions by the Federal Court of Appeal and the Alberta Court of Appeal, the AUC previously held that it will not consider a review application of an interlocutory ruling except in exceptional circumstances. While there is no established exhaustive list of exceptional circumstances, these include scenarios where the impugned decision is dispositive of a substantive right of a party, raises a constitutional issue or goes to the legality of the tribunal itself.

Salt Box did not set out what might reasonably be considered exceptional circumstances in the context of this proceeding. The AUC concluded that Salt Box had effective remedies following the issuance of a final decision in this enforcement proceeding.

***FortisAlberta Inc. Application for Direction to Pay Compensation Related to Site Transfers,* AUC Decision 28358-D01-2024**

Facilities - Value

Application

FortisAlberta Inc. ("Fortis") requested the AUC to direct the transfer of electric distribution system assets from Battle River Power Coop REA Ltd. ("BRPC") to Fortis, including the amount of compensation to be paid by Fortis to BRPC regarding the alteration of BRPC's service area ordered by the AUC in Decision 22164-D01-2018.

Proceeding 22164 involved an application by Fortis requesting that the service areas of certain rural electrification associations ("REAs") be altered to align with municipal franchise agreements ("MFAs") between Fortis and those municipalities.

Decision

The AUC ordered the transfer of certain parts of the service area previously served by BRPC to Fortis to give effect to its prior ruling in Decision 22164-D01-2018. The AUC also ordered the transfer of the related facilities associated with BRPC's electric distribution system from BRPC to Fortis. The AUC ordered Fortis to pay BRPC compensation in the amount of $313,971.

Pertinent Issues

In Proceeding 22164, Fortis requested that the service areas of certain rural electrification associations ("REAs") be altered to align them with municipal franchise agreements ("MFAs") between Fortis and various municipalities. In Decision 22164-D01-2018, the AUC determined it was in the public interest to harmonize the service areas to reflect the boundaries governed by the MFAs. The AUC altered those REA service areas that overlapped with the municipal franchise areas granted to Fortis but did not order the immediate transfer of those areas or existing REA facilities to Fortis. Instead, the transfer was made contingent on the passing of municipal bylaws requiring the customers in those areas to connect to Fortis or the occurrence of other circumstances set out in Decision 22164-D01-2018.

In this application, Fortis submitted that, since the issuance of Decision 22164-D01-2018, several municipalities have passed bylaws requiring REA members to take electric distribution service from Fortis. After numerous discussions and negotiations, Fortis and BRPC could not agree on the compensation for the assets to be transferred. Accordingly, Fortis made an application to the AUC to direct the transfer of the assets from BPRC to Fortis and to determine the compensation to be paid by Fortis to BRPC.

Since the conditions set out in Decision 22164-D01-2018 were met but the parties were unable to agree, the AUC considered it was in the public interest to order the transfer of the identified parts of BRPC's service area from BRPC to Fortis. To ensure the continued distribution of electrical energy in those parts, the AUC included in its order the transfer of the facilities that serve BRPC's former customers.

RCN-D Valuation Methodology

The AUC ordered Fortis to pay $313,971 to BRPC as compensation for the transfer of electric distribution system facilities to Fortis.

Fortis and BRPC estimated the value of the assets using the "replacement cost new less depreciation" ("RCN-D") valuation methodology. The AUC agreed that this was an appropriate valuation method in the circumstances.

Following the consideration of the inputs into and the calculation of the valuation, the AUC determined that Fortis' proposed RCN-D compensation amount of $313,971 was more reasonable than the $515,586 proposed by BRPC. In reaching this conclusion, the AUC considered the following inputs: replacement costs-new; external or internal labour; urban vs rural; contingency; land rights; and depreciation.

***AUC Inquiry Into the Ongoing Economic, Orderly and Efficient Development of Electricity Generation in Alberta – Module A Report*, AUC Decision 28501-D01-2024**

Electricity - Markets

Application

On August 3, 2023, the Government of Alberta ("GoA") issued an order-in-council ("Order") directing the AUC to hold an inquiry into the ongoing economic, orderly and efficient development of electricity generation in Alberta. The Order directed the AUC to inquire into and report on specific considerations.

Decision

The AUC issued a report ("Module A Report") and provided its observations, commitments and options on four considerations in accordance with the Order. The report was intended to assist the government with policy development and inform further study or consultation it may undertake.

Pertinent Issues

The report addressed the following four issues related to the development of power plants, as identified in the Order:

- the development of power plants on specific types or classes of agricultural or environmental land;
- the impact of power plant development on pristine viewscapes;
- the implementation of mandatory reclamation security requirements for power plants; and
- the development of power plants on lands held by the Crown in the Right of Alberta.

The report also addressed the role of municipal governments in the development and review of power plant applications.

The AUC started applying the policy changes identified in the Module A Report on March 1, 2024, which will not be applied retroactively.

The AUC provided the following observations, commitments and options in relation to the issues.

Agricultural and Environmental Land

Observations:

- The existing regulatory framework is generally sufficient for the protection of environmental land;
- There are a number of agricultural and environmental mapping tools that exist to assist proponents with siting of power plants in Alberta;
- There is no consensus about which land constitutes "prime agricultural land";
- Power plant development has not historically been a primary driver of agricultural land loss in Alberta;
- Market forces have favoured non-prime agricultural land for renewable projects, resulting in about four per cent of renewable projects locating on class 2 land as of October 2022;
- Based on the AESO high renewable net-zero scenario, and assuming all renewable development locates on class 2 land, the percentage of agricultural class 2 land loss is estimated to be less than one per cent by 2041;
- Agrivoltaic programs are an emerging tool to help mitigate agricultural impacts from projects on the land, but they would benefit from further study; and
- Municipalities want to protect agricultural land and minimize land fragmentation.

AUC Commitment:

- Explore requirements for proponents to provide soil field verification earlier in the application process.

Options:

- Assess the value of creating a province-wide integrated multi-criteria evaluation tool to identify and evaluate agricultural land;
- Do not place restrictions on use of any particular agricultural land classes. Rely on the enhancement of AUC processes, including increased municipal government involvement and focus on agricultural land preservation;
- Develop an agricultural directive as a tool to reduce agricultural land impacts;
- Restrict development on some classes of agricultural land; and
- Enhance regional planning to guide areas for development.

Pristine Viewscapes

Observations:

- There is no universal definition of a pristine viewscape; and

- Individuals value viewscapes uniquely, from their own personal perspective. The impact from power plant development on viewscapes can occur at the general public level, the community level and the individual level.

AUC Commitment:

- The Commission will enhance the existing visual impact assessment requirements within *Rule 007* to include a more structured visual impact assessment methodology within the AUC application review process.

Options:

- Provide guidance on valued viewscapes; and

- Define “no-go” restricted viewscape zones.

Reclamation Security

Observations:

- Existing power plant reclamation requirements are sufficiently defined to ensure effective reclamation, but no timing trigger exists to initiate reclamation;

- Effective construction practices to reduce land disturbance, particularly soil impacts to agricultural lands, could be better defined;

- There is no reclamation security regime that applies to all power plants;

- The reclamation risk profile for renewable power plants is relatively lower than other industries’ reclamation risks as there is no fuel depletion risk and a lower contamination risk;

- There were mixed views of whether a mandatory reclamation security regime for power plants should be implemented; and

- Parties had a range of recommendations for an acceptable reclamation security regime, with proponents proposing the least stringent requirements and landowners proposing the most stringent requirements.

AUC Commitment:

- The Commission will review *Rule 007* requirements regarding proponent commitments in relation to reclamation and security funding obligations.

Options:

- If implementing a reclamation security regime, set key outcomes, principles, and parameters for the regime; and

- If implementing a reclamation security regime, a range of options are available for the government to ensure the proponent funds all reclamation costs.

Crown Land

Observations:

- There was general support for enabling power plant development on Crown land, as long as key concerns are addressed through the review and approval processes. Development of brownfield, industrial or previously disturbed sites should be prioritized;

- First Nations and Métis communities are concerned about Crown land power plant development impacting their rights; and

- Parties identified challenges associated with developing power plants on Crown land, including lack of proximity to transmission and renewable resources.

Options:

- Perform a benefit-screening exercise to determine if it is worth implementing a policy to use Crown land for power plant development;

- Rely on existing processes utilized for the disposition of Crown land by the government and the review of power plant applications by the AUC; and

- Implement a new two-step land disposition process for Crown land dispositions by the government, and continue to rely on the existing process for review of power plant applications by the AUC.

Role of Municipal Governments

Observations:

- Municipal participation in AUC proceedings has been increasing;
- Municipalities want changes to how the AUC considers land-use planning and other municipal issues in AUC proceedings; and
- With AUC enhancements to its process, changes to Section 619 of the *Municipal Government Act* are not necessary.

AUC Commitments:

- Municipal participation rights will be automatically granted and municipalities will be eligible to request cost recovery for participation; and
- The Commission will undertake a review of *Rule 007* related to municipal submission requirements and clarify consultation requirements.

EPCOR Energy Alberta GP Inc. Updated 2024 Interim Regulated Rate Tariff Non-Energy Rates, **AUC Decision 28457-D01-2024**
Rates – Rate Increase

Application

EPCOR Energy Alberta GP Inc. ("EPCOR") applied for approval of its updated 2024 interim regulated rate tariff ("RRT") non-energy rates.

Decision

The AUC approved EPCOR's updated 2024 interim RRT non-energy rates, effective April 1, 2024.

Pertinent Issues

In September 2023, EPCOR requested approval of its 2023-2025 RRT non-energy rates. The AUC set a process for the application that allowed EPCOR and interveners to enter negotiations. In February 2024, EPCOR submitted a partial negotiated settlement agreement ("NSA") to the AUC for approval. The NSA resolved all matters of EPCOR's 2023-2025 RRT non-energy rates application except for the recovery of credit costs. Following the submission of the partial NSA, EPCOR requested approval from the AUC to update its 2024 interim RRT non-energy rates.

The AUC agreed with EPCOR that the current 2024 interim RRT non-energy rates are outdated and lower than the 2024 rates forecast. The AUC found that an increase to the current interim 2024 RRT non-energy rates was reasonable given the changes to site counts and revenue requirements that have occurred since 2022. The impact of the increase in the 2024 interim RRT non-energy rates for residential customers was approximately $0.50 per month, which will not result in rate shock for customers and will help reduce the amount of the required true-up when the final RRT non-energy rates are approved for 2024.

Green Block Mining Corp. Decision on Application for Review and Variance of Decision 26379-D05-2023 and Decision 28792-D01-2024 – Settlement Agreement with Green Block Mining Corp., formerly Link Global Technologies Inc.**, AUC Decision 28869-D01-2024**
Administrative Penalty – Extension

Application

Green Block Mining Corp. ("Green Block") sought a second extension of the deadline for payment of the outstanding amount of an administrative penalty the AUC ordered in Decision 26379-D05-2023. The AUC granted Green Block's first extension request in Decision 28792-D01-2024, issued in December 2023, after Green Block made a partial payment of the administrative penalty.

In the AUC's view, this request was effectively an application to review and vary the orders in both Decision 26379-D05-2023 and Decision 28792-D01-2024, the latter of which set the current February 21, 2024, deadline for payment.

Green Block requested a further extension to September 30, 2024, and submitted that, as a good faith gesture of its commitment to fully pay the administrative penalty, it would make an additional partial payment.

Decision

The AUC did not grant a further extension to Green Block to pay the balance of the administrative penalty ordered in Decision 26379-D05-2023.

Pertinent Issues

Green Block explained that it experienced difficulty raising money to pay the outstanding balance because it had still not completed the audit of its financial statements. Green Block was not able to say when the audit will be completed but suggested it will not be before May 2024.

The AUC noted that the issue of the outstanding audit of Green Block's financial statements has been ongoing for more than 20 months. In the settlement agreement, which was approved in Decision 26379-D05-2023, Green Block agreed to file its audited financials by December 31, 2023. Based on the history of delay in the completion of the audit of its financial statements, the AUC questioned whether Green Block would complete the audit by May 2024, as suggested. Green Block ought to have arranged its affairs to ensure payment of the administrative penalty in a timely manner, as agreed upon with the AUC enforcement staff.

Notwithstanding Green Block's latest additional partial payment of $20,000.00 and the challenge of raising money, the AUC denied Green Block's request for an extension to pay the outstanding balance of $186,500.00 of the administrative penalty ordered in Decision 26379-D05-2023.

***Apex Utilities Inc. 2024 Annual Performance-Based Regulation Rate Adjustment,* AUC Decision 28583-D02-2024**

Rates – Special Charges

Application

Apex Utilities Inc. ("AUI") applied for approval of the 2024 annual performance-based regulation ("PBR") rate adjustment filed according to the third generation PBR ("PBR3") plan.

Decision

The AUC found that the applied-for 2024 rates were determined following the provisions of the PBR3 plan approved in Decision 27388-D01-2023, except for the following revisions:

(a) a modification to the K bar retirements calculation;

(b) the approval of a residential Remove and Test Meter fee of $274 instead of the proposed $417 fee; and

(c) the denial of a reallocation of $0.22 million to Delivery revenue from other revenue due to the special charges fees update.

Pertinent Issues

On October 4, 2023, the AUC issued Decision 27388-D01-2023 setting out the parameters of the new PBR3 plan in place for the 2024-2028 term. As directed in that decision, on November 3, 2023, AUI submitted its compliance filing by way of a 2024 annual PBR rate adjustment filing, requesting approval of its 2024 going-in delivery revenue, deferral accounts and riders, and billing determinants and corresponding rate schedules. AUI also requested approval of updates to its terms and conditions of service and special charges.

The AUC ordered that AUI's 2024 distribution rates, including the deferral accounts and riders, approved in Decision 28583-D01-2023, shall continue to apply on an interim basis. The AUC approved AUI's terms and conditions for gas distribution service, approved in Decision 28583-D01-2023, on a final basis. The AUC also approved AUI's Special Charge Schedule for 2024, on a final basis, effective April 1, 2024.

***Airport City East Ltd. Airport City Solar Project,* AUC Decision 27885-D01-2024**

Facilities – Duty to Consult

Application

Airport City Solar East Ltd. ("ACSE") requested approval to construct and operate the 112-megawatt ("MW") Airport City Solar power plant (the "Project") bordering the Edmonton International Airport ("EIA"), near Leduc, Alberta. ACSE also applied to connect the Project to the FortisAlberta Inc. electric distribution system.

The application triggered two constitutional issues. The first issue was the Crown's duty to consult. Second, because the Project will be located on Crown land, ACSE questioned the applicability to the Project of certain provincial legislation, such as the *Water Act, Environmental Protection and*

Enhancement Act, the *Weed Control Act*, and the *Wildlife Act*.

Decision

The AUC approved the application from ACSE. The AUC determined that ACSE met its duty to consult with the Lac Ste. Anne Métis Community Association (“LSAMCA”).

Further, the AUC decided that ACSE did not meet its burden to establish the inapplicability of any provincial legislation.

Pertinent Issues

Applicability of Specific Provincial Laws

ACSE submitted that provincial environmental laws do not apply to the Project because: (i) it is located on federal Crown land, (ii) it is closely integrated with the aviation and aeronautics federal undertaking of the EIA, (iii) it is subject to federal environmental requirements, and (iv) the Edmonton Regional Airport Authority (“ERAA”) has exercised its statutory jurisdiction and determined that the Project will not cause any significant environmental impacts.

ACSE raised two constitutional grounds in support of its position that provincial environmental laws do not apply in these circumstances: the doctrine of interjurisdictional immunity and federal paramountcy.

Interjurisdictional Immunity

Interjurisdictional immunity applies when the impugned provisions trench on the core of an exclusive head of power under the *Constitution Act, 1867*, and the effect of this overlap impairs the exercise of the core of that head of power. The AUC held that the environment is not a matter that is exclusive to either the federal or provincial level of government. Rather, the environment touches several heads of power assigned the respective levels of government. The Supreme Court of Canada recently confirmed that both levels of government can pass laws dealing with those aspects of environmental protection that fall within their constitutional authority.

The AUC found ACSE did not demonstrate that the provincial environmental laws impair the core of federal jurisdiction over federal Crown land and the federal undertakings of aviation and aeronautics.

Paramountcy

The doctrine of paramountcy provides that, when a validly enacted federal law conflicts with a validly enacted provincial law, the provincial law is rendered inoperative to the extent of the conflict. Conflict may arise where: (i) there is an operational conflict because it is impossible to comply with both laws; or (ii) although it is possible to comply with both laws, the operation of the provincial law frustrates the purpose of the federal enactment.

The AUC found that mere duplication is not sufficient to trigger the doctrine of paramountcy, particularly when both laws can be complied with. Both levels of government can pass laws dealing with those aspects of environmental protection that fall within their constitutional authority and the mere existence of federal notice of determination regarding the Project does not create a conflict with provincial laws. Accordingly, the AUC found that ACSE failed to demonstrate any conflict that would cause the otherwise valid provincial laws to not apply.

The AUC found that the Project was subject to provincial environmental laws, regulations and standards and premised its approval of the Project on the understanding that ACSE will comply with these laws, regulations and standards.

Duty to Consult

The AUC determined that the duty to consult was triggered by this application and that consultation was owed particularly to the LSAMCA. The duty to consult always rests with the Crown, which may delegate certain procedural aspects of consultation. The duty to consult arises when the Crown has knowledge of the potential existence of an Aboriginal right, title or interest, and contemplates Crown conduct that might adversely affect it.

The AUC is not the Crown or its agent, and it has not been delegated the Crown’s duty to consult. However, an application before the AUC may trigger the duty to consult if the AUC’s decision could adversely affect a recognized or asserted right. Where the duty to consult is so triggered, the Crown may rely on the AUC’s process to assess and fulfil that duty by addressing potential impacts on Aboriginal rights.

The AUC stated that it applied its hearing process to understand the concerns raised by LSAMCA. Based on the information available, and given the conditions imposed on ACSE in this approval, the AUC determined that the Project would have a low, if any, impact on LSAMCA. The AUC concluded that consultation with LSAMCA was adequate and that the potential impact on Métis harvesting and traditional land use arising from the Project is low.

Environmental Effects

Issues arose regarding the Project's layout as it infringed on permanent watercourses to an unacceptable degree. The Project area is mostly agricultural land and the environmental impact assessment submitted by ACSE indicated that one of the watercourses in the Project area is Deer Creek. While ACSE originally committed to a 10-meter setback from watercourses, it stated that the closest distance of a solar panel to the centreline of a small permanent watercourse would be 2.6 meters. ACSE stated that the Project's commercial viability would be impacted should the AUC enforce the watercourse setbacks contained in the *Wildlife Directive for Alberta Solar Energy Projects*. The AUC reiterated that ACSE is subject to provincial regulatory standards, including those regarding Project siting. Even if provincial standards did not apply to ACSE, the AUC would still need to be satisfied that the Project is in the public interest having regard to its environmental effects, including effects on wildlife habitat.

The AUC determined that approving the proposed layout could compromise the integrity of the watercourses and wildlife habitat within the Project area. Accordingly, the Project was approved on the condition that ACSE applies a setback with a minimum of 30 meters from the top of the break of small permanent watercourses or to the adjacent riparian zone, whichever is greater.

The AUC observed that this Project is unique in its risk to birds given its proximity to EIA, which is a major international airport. EIA has a full-time bird deterrent program in place that includes the Project area. As a result, and because of further mitigation proposed by ACSE, the AUC accepted that the bird mortality risk from the Project is low. The AUC noted its expectation that the EIA and ACSE will work together to make sure that the EIA's existing bird monitoring and deterrent program encompasses the Project and remains in place for the life of the Project.

The AUC determined that the application and the Project comply with all other rules and regulations, including *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* ("*Rule 007*"), *Rule 012: Noise Control* ("*Rule 012*"), *Rule 033: Post-approval Monitoring Requirements for Wind and Solar Power Plants* ("*Rule 033*") and the *Hydro and Electric Energy Act* ("*HEEA*").

The AUC determined that approval of the Project was in the public interest, subject to specific conditions to ensure that the requirements of the applicable rules and regulations are met and that ACSE provides a Project update to show compliance with imposed conditions.

***ATCO Electric Ltd. 2024 Annual Performance-Based Regulation Rate Adjustment*, AUC Decision 28570-D02-2024**

Facilities - Solar

Application

ATCO Electric Ltd. ("AE") submitted its 2024 annual performance-based regulation ("PBR") rate adjustment filing pursuant to the provisions of the third generation PBR ("PBR3") plan. AE requested approval of its updated 2023 utility revenue requirement, which forms the basis for the going-in rates for the 2024-2028 PBR term, on a final basis and approval of its 2024-2028 K-bar on an interim basis. AE also sought confirmation for its compliance with directions given in Decision 26615-D01-2022, Decision 27672-D02-2022 and Decision 27388-D01-2023.

Decision

The AUC found that AE's proposed distribution rates were determined in accordance with the provisions of the PBR3 plan approved in Decision 27388-D01-2023. The AUC determined that no changes were required to the 2024 distribution rates, including the system access service ("SAS") rates, distribution-connected generation ("DCG") credits, riders, the customer and retailer terms and conditions ("T&Cs") for electric distribution service, as well as the stand-alone schedules of Available Company Investment and of Supplementary Service Charges previously approved on an interim basis in Decision 28570-D01-2023.

Pertinent Issues

The first year of the PBR3 plan is 2024. It follows the cost-of-service 2023 rebasing year. The PBR3 framework approved in Decision 27388-D01-2023 provides a rate-setting mechanism (price cap for electric distribution utilities and revenue per customer cap for gas distribution utilities). During the PBR3 term, rates are adjusted annually using a formula that includes an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X"). Except for specifically approved adjustments, a utility's revenues are not linked to its costs during the PBR term.

In Decision 27388-D01-2023, the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (Y factors) and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor).

For the PBR3 plan, the AUC continued to divide capital into Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with defined eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provides an amount of capital funding each year of the PBR3 plan based, in part, on capital additions made during the PBR2 term.

Each distribution utility's annual PBR rate adjustment filing addresses all applicable parameters relevant to the establishment of the PBR rates and T&Cs for that utility for a given year and relies on certain filed information to establish rates.

The AUC ordered that AE's distribution rates, including the SAS rates, DCG credits and riders approved in Decision 28570-D01-2023, shall continue to apply. The AUC approved on a final basis AE's updated customer and retailer T&Cs for electric distribution service, approved in Decision 28570-D01-2023.

***Aura Power Renewables Ltd. Peace Butte Solar Farm and Battery Storage Project,* AUC Decision 28259-D01-2024**

Facilities - Solar

Application

Aura Power Renewable Ltd. ("Aura Power") applied for approval to construct and operate the 230-megawatt ("MW") Peace Butte Solar Farm and Battery Storage Project (the "Project"), located in Cypress County. The Project consisted of a 230-MW solar power plant, a battery energy storage system ("BESS") with a storage capacity of up to 75 MW/270 megawatt-hour ("MWh") and the associated Black and White 1136S Substation (the "Substation").

Decision

The AUC approved the application, subject to conditions.

Pertinent Issues

The Project, which included 521,000 bifacial photovoltaic modules on a single axis tracking system, 72 inverters and underground collector lines, will be constructed on 820 acres of private land. The land at the site is classified as Class 3 and below agricultural land.

In this proceeding, Aura Power responded to the information requirements established by *Bulletin 2023-05: Interim Rule 007 Information Requirements*.

The application from Aura Power was subject to the approvals pause mandated by the *Generation Approvals Pause Regulation*, which regulation expired. The AUC determined that no further process was required in this proceeding.

The AUC determined that approval of this application was in the public interest having regard to the social, economic and other effects of the project, including its effect on the environment.

The AUC found that the information submitted by Aura Power and stakeholder consultation met the requirements set out in *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* the *Alberta Utilities Commission Act* ("*Rule 007*"), the *Hydro and*

Electric Energy Act (“*HEEA*”) and the *Rule 007* interim information requirements.

The AUC accepted that the Project presents an overall low risk to wildlife and wildlife habitat since it is entirely sited on private cultivated lands that are not irrigated, which has a reduced impact on the environment due to the disturbed nature of the land use. The AUC was satisfied that, with diligent implementation of the mitigation measures and the commitments made by Aura Power in this proceeding, the identified environmental effects of the Project can be mitigated to an acceptable degree.

The AUC found that the noise impact assessment (“NIA”) for the Project met *Rule 012: Noise Control* (“*Rule 012*”) requirements and accepted that noise from the Project will comply with this rule.

The AUC imposed conditions of approval for the Project in relation to post-construction monitoring, solar glare, the battery technology for the energy storage system, the emergency response plan, and the final equipment selection.

The AUC accepted that Aura Power’s approach to reclamation was sufficient to satisfy the AUC that approval of the Project was in the public interest. The AUC expressed an expectation that applicants will fully reclaim projects and bear the costs, including Aura Power.

The AUC expressed an understanding that Aura Power will be responsible for posting security following the updated reclamation security regime, given that the Project was approved after March 1, 2024, which is in accordance with the government’s policy guidance related to reclamation security provided to the AUC on February 28, 2024.

Peace River Energy Project Inc. Peace River Energy Project and Interconnection, **AUC Decision 28616-D01-2024**

Rates - Electricity

Application

Peace River Energy Project Inc. (“PREP”) applied for approval to construct and operate the 4.99-megawatt (“MW”) Peace River Energy Project solar power plant (the “Project”), located approximately 1.1 kilometers west of Peace River. PREP also applied to connect the Project to ATCO Electric Ltd.’s 25-kilovolt distribution system.

Decision

The AUC approved PREP's applications, finding the approval in the public interest.

Pertinent Issues

The AUC determined that the information requirements in *Rule 007: Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines* (“*Rule 007*”) were met and that the participant involvement program for the Project met the requirements of *Rule 007*.

In its participant involvement program, PREP identified an objecting resident. In communications with this resident, PREP committed to install a vegetative screen to reduce the visual impacts of the Project at the stakeholder’s residence. The AUC expressed an expectation that PREP will uphold its commitments. The AUC noted that it did not receive any submissions in response to its notice of application, which indicated that stakeholders have no outstanding concerns about the Project.

The AUC was satisfied that the Project’s environmental and agricultural effects were either minor in nature or can be mitigated to an acceptable degree. Overall, the AUC found that the proposed lands, mitigations and potential dual use commitments adequately addressed the agricultural considerations.

The AUC was satisfied with PREP’s commitment to establish a reclamation reserve account with the land lease owner as beneficiary and set aside the reclamation security in a reclamation account in the last 10 years of the Project life.

The AUC did not have any concerns with the preliminary emergency response measures, site monitoring and communication protocols.

The AUC found that the noise impact assessment summary submitted by PREP met the requirements of *Rule 012: Noise Control* (“*Rule 012*”) and accepted the conclusion that noise from the Project will comply with the permissible sound levels.

The AUC accepted that, given the small size of the Project and the nature of the surrounding landscape, the Project was expected to have a very limited overall impact on the identified viewscapes.

The AUC imposed conditions of approval regarding annual post-construction monitoring, solar glare and the final project update.

***Kinbrook Solar, GP Inc. and Solar Krafte Utilities Inc. Rainier Solar Farm,* AUC Decision 28439-D01-2024**

Rates - Electricity

Application

Kinbrook Solar, GP Inc. and Solar Krafte Utilities Inc. (the "Applicants") applied to construct and operate a 450-megawatts ("MW") solar power plant designated as Rainier Solar Farm, and the Rainier 1050S Substation (the "Project"), located six kilometers southwest of the City of Brooks.

Decision

The AUC found that approval of the Project would not be in the public interest given its unmitigable negative effects on the environment and wildlife, and denied the applications.

Pertinent Issues

The AUC determined that, in accordance with the *Alberta Wildlife Directive for Alberta Solar Energy Projects* ("*Directive*"), appropriate site selection at the landscape level is the first and most critical factor in preventing significant negative effects on wildlife. The AUC found that most of the Project was sited on native grassland, which was evaluated by Alberta Environment and Protected Areas ("AEPA") to be a high risk to native and critical habitats. The AUC held that diverse wildlife, including multiple species of management concern, use the native and critical habitats on which the Project was situated.

In the AUC's view, the Applicants failed to demonstrate that the amount of pre-existing human-made disturbance in the Project area reduced the value of native and critical habitats or that this disturbance justified a departure from the *Directive*'s avoidance standard. The AUC concluded that, given the importance of site selection for avoiding impacts to native and critical habitats, the Applicants' proposed mitigations were not adequate to reduce the environmental impacts on wildlife and the availability of native and critical habitats to an acceptable level.

The AUC concluded that the approval of the applications was not in the public interest and denied the applications in accordance with ss 11, 14, 15 and 19 of the *Hydro and Electric Energy Act* ("*HEEA*").

***Pivotal Energy Partners Inc. Application for an Order Permitting the Sharing of Records Not Available to the Public Regarding the Bantry Power Plant and Parkland Power Plant,* AUC Decision 28894-D01-2024**

Rates - Electricity

Application

Pivotal Energy Partners Inc. ("Pivotal Energy") applied under s 3 of the *Fair, Efficient and Open Competition Regulation* ("*FEOCR*"), seeking permission to share records not available to the public regarding the 7.2-megawatt ("MW") Bantry Power Plant and the 10.275 MW Parkland Power Plant. Pivotal Energy applied to share records with URICA Energy Real Time Ltd.

Decision

The AUC was satisfied that Pivotal Energy demonstrated that: (i) the sharing of records was reasonably necessary for Pivotal Energy to carry out its business; and (ii) the subject records would not be used for any purpose that did not support the fair, efficient and openly competitive operation of the Alberta electricity market. The AUC was also satisfied that the total offer control of the parties would not exceed the offer control limit of 30 percent under s 5(5) of the *FEOCR*. The AUC approved the application.

***ENMAX Power Corporation 2024 Annual Performance-Based Regulation Rate Adjustment,* AUC Decision 28575-D02-2024**

Rates - Electricity

Application

ENMAX Power Corporation ("ENMAX") submitted its 2024 annual performance-based regulation ("PBR") rate adjustment filing pursuant to the provisions of the third generation PBR ("PBR3") plan. ENMAX requested approval of its 2024 electric distribution access service ("DAS") rates and riders, transmission system access service ("SAS") rates, and billing determinants and corresponding rate schedules in accordance with the parameters of the PBR3 plan. ENMAX also requested approval of its customer and retailer terms and conditions ("T&Cs") of electric distribution service. Additionally, ENMAX included in the application its 2022 transmission access charge deferral account ("TACDA") true-up and requested the related true-up amounts be collected or refunded through a transmission access charge ("TAC") rider.

Decision

The AUC found that ENMAX's 2024 distribution rates proposed in the application were determined in accordance with the provisions of the PBR3 plan approved in Decision 27388-D01-2023. The AUC determined that no changes were required to the 2024 distribution rates, including the SAS and riders, as well as the T&Cs for electric distribution service previously approved on an interim basis in Decision 28575-D01-2023.

Pertinent Issues

The first year of the PBR3 plan is 2024. It follows the cost-of-service 2023 rebasing year. The PBR3 framework approved in Decision 27388-D01-2023 provides a rate-setting mechanism (price cap for electric distribution utilities and revenue per customer cap for gas distribution utilities). During the PBR3 term, rates are adjusted annually using a formula that includes an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X"). Except for specifically approved adjustments, a utility's revenues are not linked to its costs during the PBR term.

In Decision 27388-D01-2023, the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (Y factors) and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor).

For the PBR3 plan, the AUC continued to divide capital into Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with defined eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provides an amount of capital funding each year of the PBR3 plan based, in part, on capital additions made during the PBR2 term.

Each distribution utility's annual PBR rate adjustment filing addresses all applicable parameters relevant to the establishment of the PBR rates and T&Cs for that utility for a given year and relies on certain filed information to establish rates.

The AUC ordered that ENMAX's 2024 distribution rates, including the SAS rates and riders, approved in Decision 28575-D01-2023, shall continue to apply. The AUC approved ENMAX's T&Cs for electric distribution service on a final basis.

EPCOR Distribution & Transmission Inc. 2024 Annual Performance-Based Regulation Rate Adjustment, **AUC Decision 28581-D02-2024**

Rates - Electricity

Application

EPCOR Distribution & Transmission Inc. ("EDTI") submitted its 2024 annual performance-based regulation ("PBR") rate adjustment filing pursuant to the provisions of the third generation PBR ("PBR3") plan. EDTI requested approval of its 2024 electric distribution access service ("DAS") rates and riders, 2024 transmission distribution rates, including the system access service ("SAS") rates, and billing determinants and corresponding rate schedules in accordance with the parameters of the PBR3 plan. EPCOR also requested approval of its customer and retailer terms and conditions ("T&Cs") of electric distribution service. Additionally, EPCOR included in the application its 2022 transmission access charge deferral account ("TACDA") true up, and requested the related true up amounts be collected or refunded through Rider J.

Decision

The AUC found that EDTI's 2024 distribution rates proposed in this application were determined in accordance with the provisions of the PBR3 plan approved in Decision 27388-D01-2023. The AUC determined that no changes were required to the 2024 distribution rates, including the SAS rates and riders, as well as the T&Cs for electric distribution service previously approved on an interim basis in Decision 28581-D01-2023.

Pertinent Issues

The first year of the PBR3 plan is 2024. It follows the cost-of-service 2023 rebasing year. The PBR3 framework approved in Decision 27388-D01-2023 provides a rate-setting mechanism (price cap for electric distribution utilities and revenue per customer cap for gas distribution utilities). During the PBR3 term, rates are adjusted annually using a formula that includes an indexing mechanism that tracks the rate of inflation (“I”) that is relevant to the prices of inputs the utilities use, less a productivity offset (“X”). Except for specifically approved adjustments, a utility’s revenues are not linked to its costs during the PBR term.

In Decision 27388-D01-2023, the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (Y factors) and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor).

For the PBR3 plan, the AUC continued to divide capital into Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with defined eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a “K factor” adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provides an amount of capital funding each year of the PBR3 plan based, in part, on capital additions made during the PBR2 term.

Each distribution utility’s annual PBR rate adjustment filing addresses all applicable parameters relevant to the establishment of the PBR rates and T&Cs for that utility for a given year and relies on certain filed information to establish rates.

The AUC ordered EDTI’s 2024 distribution rates, including the SAS rates and riders, approved in Decision 28581-D01-2023, shall continue to apply. The AUC approved EDTI’s T&Cs for electric distribution service on a final basis.

ATCO Gas 2024 Annual Performance-Based Regulation Rate Adjustment, AUC Decision 28569-D02-204

PBR-Rates - Gas

Application

ATCO Gas (“AG”) submitted its 2024 annual performance-based regulation (“PBR”) rate adjustment filing pursuant to the provisions of the third generation PBR (“PBR3”) plan. AG requested approval of its updated 2023 revenue requirement, which forms the going-in revenue for the 2024-2028 PBR term, and approval of its 2024 K-bar on an interim basis. AG also requested approval of its 2024 distribution rates, and billing determinants and corresponding rate schedules in accordance with the parameters of the PBR3 plan, as well as approval of its 2022 revenue and K-bar amounts on a final basis, thereby resulting in final rates for that year. AG also requested approval of its customer and producer terms and conditions (“T&Cs”).

Decision

The AUC found that AG’s 2024 distribution rates proposed in this application were determined in accordance with the provisions of the PBR3 plan approved in Decision 27388-D01-2023. The AUC determined that no changes were required to the 2024 distribution rates and the customer and producer T&Cs previously approved on an interim basis in Decision 28569-D01-2023.

Pertinent Issues

The first year of the PBR3 plan is 2024. It follows the cost-of-service 2023 rebasing year. The PBR3 framework approved in Decision 27388-D01-2023 provides a rate-setting mechanism (price cap for electric distribution utilities and revenue per customer cap for gas distribution utilities). During the PBR3 term, rates are adjusted annually using a formula that includes an indexing mechanism that tracks the rate of inflation (“I”) that is relevant to the prices of inputs the utilities use, less a productivity offset (“X”). Except for specifically approved adjustments, a utility’s revenues are not linked to its costs during the PBR term.

In Decision 27388-D01-2023, the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (Y factors) and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor).

For the PBR3 plan, the AUC continued to divide capital into Type 1 and Type 2 capital. For Type 1 capital, the AUC approved a modified capital tracker mechanism with defined eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a “K factor” adjustment to the annual PBR rate-setting formula. For Type 2 capital, the AUC approved a K-bar mechanism that provides an amount of capital funding each year of the PBR3 plan based, in part, on capital additions made during the PBR2 term.

Each distribution utility’s annual PBR rate adjustment filing addresses all applicable parameters relevant to the establishment of the PBR rates and T&Cs for that utility for a given year and relies on certain filed information to establish rates.

The AUC ordered AG’s 2024 distribution rates, approved in Decision 28569-D01-2023, shall continue to apply. The AUC approved on a final basis AG’s updated customer and producer T&Cs for gas distribution service, approved in Decision 28569-D01-2023.

CANADA ENERGY REGULATOR

Enbridge Pipelines Inc. Application for Approval of the Mainline Tolling Settlement and Final Tolls, CER Letter Decision File 4637048, C28621-1

Gas – Tolls

Application

Enbridge Pipelines Inc. ("Enbridge") applied for approval of the Mainline Tolling Settlement (the "Settlement").

Decision

The Canadian Energy Regulator ("CER") approved the application, as filed.

Pertinent Issues

The CER approved the application, comprising of the following:

- approval of the Settlement in respect of the Canadian Mainline;
- approval of the Base Canadian Local Tariff Tolls and the Base International Joint Tariff Tolls set forth respectively in Schedules "C" and "B" of the Settlement, and also in Appendix B to Interim Canadian Local Tariff CER No. 529 and Appendix A to Interim International Joint Tariff CER No. 530, respectively, as final tolls from 1 July 2021 to the effective date of the first toll filings under the Settlement following the Commission's approval (Effective Date of the New Settlement Tolls);
- approval of the interim receipt and delivery tankage tolls as final tolls from 1 July 2021 to the Effective Date of the New Settlement Tolls;
- the Interim Line 3 Replacement surcharges charged between 1 July 2021 and 30 September 2021 as final tolls;
- the Line 3 Replacement surcharges charged between 1 October 2021 and the Effective Date of the New Settlement Tolls as final tolls; and
- approval to establish from 1 July 2021 through to 31 December 2028 tolls for the Canadian Mainline in accordance with the Settlement.

Inuvialuit Energy Security Project Ltd – Application for Authorization for Installation and Operation of the Energy Centre, File OF-EP-OA-I184-1414 03/4257714, C28698-1

Gas - Facilities

Application

Inuvialuit Energy Security Project Ltd. ("IESPL") applied to the Canadian Energy Regulator ("CER") for approval of the installation and operation of the Inuvialuit Energy Security Project ("IESP") Energy Centre ("Application"), pursuant to the *Northwest Territories' Oil and Gas Operations Act* ("*OGOA*"). Specifically, IESPL applied for authorization to install modules and plant infrastructure onsite, to commission and operate the gas plant, and to transport compressed natural gas and other fuels by truck to regional users ("Energy Centre Activities").

Decision

The CER approved IESPL's Application and issued the requested authorizations for a twelve-year term, from 7 March 2024 to March 7, 2036, subject to conditions.

Pertinent Issues

Background

The IESP is located on Inuvialuit private lands. The Inuvialuit own and administer the surface and subsurface interests in these private lands under the Inuvialuit Final Agreement. IESPL intends for the IESP to replace the Town of Inuvik's gas supply from the nearby Ikhil field and the supplies of liquid natural gas and propane that are trucked from southern Canada.

Assessment of the Energy Centre Application

(a) Effect on the Rights of Indigenous Peoples

No one, and notably no Indigenous Peoples or organizations potentially affected by the IESP registered to participate in the hearing. A letter of comment was submitted to the CER from the Hamlet of Tuktoyaktuk and the Tuktoyaktuk Community Corporation, indicating the full support of the Indigenous owners and residents of the lands where the IESP is located. The Crown Consultation Coordinator filed a letter summarizing the consultation steps taken indicating that it would not undertake consultation beyond the CER's regulatory process in furtherance of the Crown's duty to consult.

The CER was satisfied that the engagement and consultation was adequate for the purpose of the CER's decision on the Application and that its decision was consistent with section 35 of the *Constitution Act, 1982*.

The CER found that IESPL appropriately identified and engaged those potentially impacted by the Energy Centre Activities. The CER was also satisfied that sufficient notice was provided of the Application and the CER's assessment process and that sufficient opportunity was given to participate in the CER's hearing process. The CER was also satisfied with IESPL's commitment to continue to engage with Indigenous Peoples and organizations to resolve any project-related concerns. The CER imposed a condition requiring IESPL to track and fulfil all commitments it made in its Application and related submissions.

The CER found that the Energy Centre Activities are unlikely to adversely affect the rights of Indigenous Peoples because of the location of the Energy Centre on Inuvialuit private lands, the small scope of the activities involved, and the low potential for negative impacts on the environment and socio-economic factors during and after installation and operation. The CER accepted that the IESP was likely to benefit Indigenous Peoples and organizations in the region.

(b) Environment Matters

The CER considered the Environmental Protection Plan ("EPP") and the included environmental management plans submitted by IESPL and found that IESPL identified and committed to implementing appropriate mitigation and avoidance measures to protect the environment during the installation, commissioning, and operation of the Energy Centre. With the implementation of IESPL's mitigation measures and commitments, including the CER-imposed conditions, the CER found that the environment will be adequately protected during the Energy Centre Activities.

Due to the presence of sensitive wildlife species and their habitat, and IESPL's wildlife noise monitoring commitment in its EPP, the CER imposed a condition requiring IESPL to file either its wildlife-related noise monitoring plan or a detailed rationale for why wildlife noise monitoring is not required, at least 90 days before commencing operation of the Energy Centre. The CER also imposed a condition directing IESPL to file a digital light intensity monitoring procedure at least 90 days before commencing the installation of the Energy Centre's modules and plant infrastructure. Based on IESPL's commitment to conduct air quality modelling of the final engineering design, the CER imposed a condition requiring IESPL to file a summary of its air quality modelling results.

(c) Socio-Economic Matters

The CER found that the Energy Centre Activities will likely result in overall positive social and economic impacts, and that they will have no or negligible negative effects on socio-economic matters.

In reaching its positive impacts of the IESP conclusion, the CER considered the project's capacity to enhance economic development and security in the region through enhanced energy security, local business and employment opportunities, training and capacity building, improvements to local infrastructure, and reduction in local diesel fuel and gas costs.

In reaching its conclusion that the Energy Centre Activities will likely have no or negligible negative socio-economic effects, the CER considered the small scope of the Energy Centre Activities and their location on Inuvialuit private lands, and the low potential for impacts on socio-economic valued components, as well as IESPL's proposed mitigation measures to address any potential negative residual effects of the Energy Centre Activities.

(d) Financial Matters

The CER was satisfied that IESPL submitted sufficient evidence to support the use of a parental guarantee as proof of financial responsibility for the Energy Centre. To ensure the continued and ongoing financial position of the guarantor, the CER imposed a condition requiring IESPL to update the CER if there are any material changes in the financial position of the guarantor or its proof of financial responsibility. IESPL previously provided a parental guarantee for the early site works and well workover authorizations for the IESP. The CER imposed a condition requiring IESPL to submit a final, signed and executed copy of the parental guarantee, which includes reference to the Energy Centre, before starting installation activities.

(e) Engineering Matters

The CER found that IESPL provided a sufficient level of detail to describe the scope of the proposed Energy Centre Activities. The CER noted that IESPL committed to ensuring that the equipment to be used for the Energy Centre will be fit for purpose, as is required by s 15 of the *OGOA*. The CER noted that IESPL indicated that it continued to advance the engineering design of the Energy Centre. Because it is critical to complete detailed engineering design before commencing installation activities, the CER imposed a condition regarding the engineering design requiring IESPL to file with the CER a detailed piping and instrumentation diagram at least 60 days before starting Energy Centre installation activities.

To support the safe operation of the Energy Centre, the CER also imposed a condition that requires IESPL to file, at least 60 days before starting operation of the Energy Centre, details on the preventive maintenance system for the Energy Centre to ensure its ongoing integrity. The CER was satisfied that IESPL will follow the applicable regulations, codes, standards, and industry best practices during the installation and operation of the Energy Centre.

(f) Safety and Emergency Matters

The CER found that the safety-related information provided in the Application and related submissions, including commitments to implement recognized industry standards, demonstrated that IESPL had an adequate framework in place to manage the safe installation, commissioning and operation of the Energy Centre. The hazards identified, the evaluation of risks and proposed mitigation measures were logical and appropriate for the Energy Centre Activities. The CER imposed a condition requiring IESPL to file for approval, 14 days before commencing operation of the Energy Centre, a signed confirmation that a pre-start-up safety review was completed.

The CER found that IESPL developed comprehensive emergency response plans to manage emergencies that may occur during the Energy Centre Activities. This included processes to identify, manage and mitigate risks, and the adoption of the Incident Command System. The CER required IESPL to demonstrate that its emergency response documentation was complete before commencing installation and commissioning of the Energy Centre. The CER imposed conditions requiring IESP to file an updated copy of the IESP Energy Centre Installations Phase Emergency Response Plan, an updated IESP Energy Centre Operations Phase Emergency Response Plan and field operating guides that support emergency response, at least 90 days before starting operation.

Emergency response exercises are an integral part of an emergency management program. Accordingly, the CER imposed a condition requiring IESPL to hold a functional or full-scale emergency response exercise to evaluate the effectiveness of the IESP Energy Centre Operations Phase ERP, associated procedures, including emergency response training, within 12 months of commencing operation of the Energy Centre. IESPL must notify the CER a minimum of 180 days before the exercise and file a copy of the exercise after-action report with the CER within 45 days of completing the exercise. The CER included a notification timeline of 180 days to assist in planning CER participation. To ensure that the CER has a current copy on file of the Energy Centre ERP during IESP operations, and considering that the IESP is intended to operate for several decades, the CER imposed a condition requiring IESPL to file with the CER, on an annual basis until the end of operation of the Energy Centre, an updated electronic copy of the ERP or written confirmation from a responsible officer of IESPL that there have been no changes from the previous year.

SUPREME COURT OF CANADA

***Yatar v. TD Insurance Meloche Monnex*, 2024 SCC 8**

Administrative Law - Judicial Review v. Statutory Appeal

Ummugulsum Yatar ("Ms. Yatar") contested the denial of her insurance benefits, following an accident in 2010. After having her application dismissed by the Licence Appeal Tribunal ("LAT") in 2019, due to the matter being time-barred, Ms. Yatar requested reconsideration of this decision, which was dismissed. Then, she simultaneously appealed the reconsideration decision before the Divisional Court of Ontario ("Divisional Court") and applied for judicial review. The *Licence Appeal Tribunal Act, 1999* ("*LATA*"), provided that an appeal from a decision of the LAT relating to a matter under the *Insurance Act* ("*IA*"), may be made on a question of law only. The Divisional Court concluded that there were "no exceptional circumstances" in this case that would justify judicial review and declined to grant the application for judicial review.

While the Court of Appeal for Ontario ("Court of Appeal") concluded that judicial review of the LAT adjudicator's decision ought not to have been considered, it held that the application for judicial review would have been denied as the LAT adjudicator's decision on the reconsideration was reasonable.

Decision

The Divisional Court erred when it concluded that only in "exceptional circumstances" would judicial review be available where there is a limited right of appeal. The Court of Appeal erred when it held that judicial review would be exercised only in "rare cases" and that, in this case, Ms. Yatar had an appropriate alternative remedy.

According to *Canada (Minister of Citizenship and Immigration) v. Vavilov* ("*Vavilov*"), a right of appeal does not preclude an individual from seeking judicial review for questions not dealt with in the appeal. Despite the statutory right of appeal limited to questions of law, judicial review is available for questions of fact or mixed fact and law as a matter of discretion regarding whether to undertake judicial review, having regard to the framework for analysis set out in *Strickland v. Canada (Attorney General)* ("*Strickland*").

The appeal was allowed, and the matter was referred to the LAT adjudicator for reconsideration.

Pertinent Issues

The main issue in this appeal was related to the decision by the Divisional Court and the Court of Appeal not to undertake judicial review. As this is a discretionary decision, deference is to be shown. However, the exercise of discretion can be set aside when a judge considered irrelevant factors, failed to consider relevant factors or reached an unreasonable conclusion. While there is a right to seek judicial review, it is open to the judge before whom judicial review is sought to decide whether to exercise his or her discretion to grant relief.

When an applicant brings an application for judicial review, a judge must consider the application and, at a minimum, the judge must determine whether judicial review is appropriate. If, in considering the application, the judge determines that one of the discretionary bases for refusing a remedy is present, he or she may decline to consider the merits of the judicial review application. The judge also has the discretion to refuse to grant a remedy, even if he or she finds the decision under review unreasonable.

The exercise of discretion requires the court to determine the appropriateness of judicial review. The court should consider the available alternative and the suitability and appropriateness of judicial review in the circumstances. The question is whether some other remedy is adequate and whether judicial review is appropriate. This balancing exercise should consider the purposes and policy considerations underpinning the legislative scheme in issue.

Both the Divisional Court and the Court of Appeal sought to apply Strickland but erred in principle by relying on a statutory right of appeal for questions of law as indicative of legislative intent to restrict access to judicial review for questions of fact and mixed fact and law. No such inference was warranted. Properly applying Strickland, the Divisional Court should have exercised its discretion to undertake judicial review for issues not dealt with under the statutory right of appeal.

Once it is determined that it is appropriate to undertake judicial review, the issue is whether the LAT adjudicator's reconsideration decision is reasonable. The LAT adjudicator's reconsideration decision was unreasonable, as he failed to consider the effects of the reinstatement of benefits on the limitation period and did not have regard to jurisprudence relevant to the matter.