REGULATORY LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA COURT OF APPEAL

***AlphaBow Energy Ltd v Alberta Energy Regulator*, 2023 ABCA 164**
Electricity - Stay Application

Application

AlphaBow asked the AER to grant it a regulatory appeal of a decision issued by the AER (the "Decision"), and a stay of portions of the order following the Decision. The AER dismissed AlphaBow's application for a stay pending the AER's determination of AlphaBow's request for regulatory appeal. In this decision, the Alberta Court of Appeal ("ABCA") considered AlphaBow's request to stay certain parts of the Decision.

Decision

The ABCA dismissed the application for stay. It determined that Rules 3.23(1), 14.37(1), and 14.48 of the *Alberta Rules of Court* are not broad enough to authorize a single judge to stay an order of the AER that is not the subject of a permission-to-appeal application to the ABCA. Moreover, the ABCA's inherent jurisdiction or implicit authority cannot be invoked to obtain such authority.

Applicable Legislation

Alberta Rules of Court

Pertinent Issues

Rule 14.48 of the *Alberta Rules of Court* specifically deals with applications for a stay of a decision of a judge from the Court of King's Bench. The ABCA held that the fact that Rule 14.1(1)(f) defines "decision" broadly does not change the nature of the decision-maker. The definition incorporates the decisions of and creates a specific rule for a particular decision-maker. Therefore, Rule 14.48 cannot apply.

Rule 14.37 of the *Alberta Rules of Court* authorizes a single appeal judge to "decide any application incidental to an appeal". Although AlphaBow has a pending permission-to-appeal application relating to another AER decision, it was not sufficiently linked to the Decision to warrant that the authority contained in Rule 14.37 can be invoked.

Rule 3.23(1) of the *Alberta Rules of Court* will not apply, as it is available only if the applicant has filed an originating application for judicial review.

The lawmakers have already delineated the extent of jurisdiction of a single appeal judge to grant the stay of an order. The court's inherent power cannot be used to create an additional head of power not bestowed on the ABCA by legislation or regulation.

ALBERTA ENERGY REGULATOR

***Increased Risk of Wildfire During Drier Seasons*, AER Bulletin 2023-25**
Oil and Gas - Monitoring

The AER reminded licensees that the risk of brush/grass fires increases significantly during wildfire season, which is from March 1 to October 31. The Alberta Agriculture and Forestry ("AAF") has a tiered fire ban system restricting activities that may cause wildfires in the Forest Protection Area. The AAF may impose restrictions on the use of off-highway vehicles ("OHV"), used by industry, and for recreation.

Proactive fire control measures must be considered, including developing emergency response plans and acquiring and maintaining fire suppression equipment. Licensees should communicate with local fire departments to coordinate their mutual aid response during an emergency. Additionally, the AER recommended that operators: (i) adhere to a regular preventive maintenance schedule for flare stacks; (ii) regularly examine flares for carbon or soot buildup around the flare tip; and (iii) adequately pull apart and verify that older approved burn/brush piles are fully extinguished. To prevent vehicle-related fires, operators should ensure that OHVs have spark arrestors inside the muffler, vehicles are not parked with hot exhausts in dry grass areas, and regular checks are performed to ensure that nothing has ignited.

Operators and licensees must adhere to *AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*; *Alberta's Forest and Prairie Protection Act* and *Directive 071: Emergency Preparedness and Response*.

ALBERTA UTILITIES COMMISSION

***Air Products Canada Ltd. Edmonton 3 H2 Power Plant, Substation and Industrial System Designation,* AUC Decision 27380-D01-2023**

Electricity - Facilities

Application

Air Products Canada Ltd. ("APC") applied for permission to construct and operate a 90.5-megawatt combined-cycle power plant and a substation at its proposed hydrogen facility - the Edmonton 3 H2 Plant. APC also applied for an order designating the power plant and substation facilities as an industrial system ("ISD").

Decision

The AUC approved the applications from APC.

Applicable Legislation

AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*

AUC Rule 012: *Noise Control*

Alberta Utilities Commission Act, SA 2007, c A-37.2.

Alberta Ambient Air Quality Objectives and Guidelines.

Electric Utilities Act, SA 2003, c E-5.1.

Environmental Protection and Enhancement Act, RSA 2000, c E-12.

Hydro and Electric Energy Act, RSA 2000, c H-16.

Pertinent Issues

The majority of the electricity supplied by the power plant will be used by the Edmonton 3 H2 Plant and any excess electricity will be exported to the Alberta Interconnected Electric System. The Edmonton 3 H2 Plant, including the power plant, substation, and hydrogen facility is designed to achieve net-zero greenhouse gas emissions and is likely to result in significant benefits to Albertans.

The AUC found that the facilities applications met the requirements set out in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines and* Rule 012: *Noise Control*.

The AUC acknowledged that emissions from the proposed power plant would exceed the *Alberta Ambient Air Quality Objectives* for cumulative fine particulate matter. The AUC however determined that the contribution is minor relative to the existing background concentration.

The AUC found that APC's application for ISD met the principles and criteria for ISD because as Air Products owns and operates both the hydrogen facility and the electric facilities, and there is therefore a high degree of integration of management of the components and the processes of the industrial operations.

***Alberta Electric System Operator Independent System Operator Tariff Modernization Application,* AUC Decision 27864-D01-2023**

Electricity - Rates

Application

The Alberta Electric System Operator ("AESO") applied for revisions to the Independent System Operator ("ISO") tariff. The proposed revisions related to the AESO's existing practices and processes for reviewing system access service ("SAS") requests (the "SASR revisions"), the generating unit owner's contribution ("GUOC"), and the costs of complying with applicable emissions legislation in the existing compensation formula for the provision of conscripted transmission must-run service (the "TMR revisions"), as well as introducing associated new or amended definitions in the Alberta Electric System Operator ("AESO")'s *Consolidated Authoritative Documents Glossary*.

Decision

The AUC approved the application as filed, with one exception. The AUC directed the AESO to revise its proposal concerning the terms and conditions applicable to the GUOC to reflect the alternative approach provided by the AESO in its final argument.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1.

Transmission Regulation, Alta Reg 86/2007.

ISO Rules.

Pertinent Issues

The AESO determined the scope of the revisions sought in the application based on stakeholder consultation. The AESO sought approval of revisions that it considered would be non-controversial, would improve clarity and reduce repetition, and better reflect the AESO's existing practices and process. The AESO took and intends to continue taking, a modular or phased approach to tariff filings, applying more frequently for the approval of separate tariff components as part of smaller tariff filings, rather than submitting large general tariff applications every three or four years.

The TMR Revisions

The AESO proposed to amend the ISO tariff to allow a generator that provides uncontracted TMR service, in response to an AESO directive, to be compensated for the actual emissions costs incurred. The AESO also proposed to extend the invoicing period for emissions compliance costs to prevent a generator from being required to issue invoices before knowing the actual emissions compliance costs. The AUC approved these revisions as filed.

The SASR Revisions

The AESO submitted that revisions to the SASR related sections were necessary to better align with, and clarify the AESO's existing practices and processes for the review of SASRs submitted by market participants.

Interveners argued that the revisions related to the timing for execution of SAS agreements in s 3.6(1)(b) and notification of changes to a SASR in s 3.9(2) of the ISO tariff should not be approved as the revisions reduce the transparency, intelligibility, and certainty of the ISO tariff and negatively impact investor certainty and the fair, efficient and openly competitive operation of the Alberta Interconnected Electric System. In the AUC's view, the proposed revisions to s 3.6(1)(b) reflect no change to the scope of discretion that the AESO currently holds under s 3.6(1)(b). The AESO, in creating practices in the ISO tariff such as requiring market participants to execute SAS agreements at certain times, using certain forms containing certain information if a new or an amended needs approval is required for a connection project, assists the AESO in satisfying its duties set out in s 6(1) of the *Transmission Regulation*. Consequently, the AUC approved the AESO's requested SASR revisions to s 3.6(1)(b) and s 3.9(2) as filed.

The New Definitions

The AUC approved the AESO's proposed new exhaustive definition for "system transmission facilities" because it found that the change is purely administrative in nature, will not impact the AESO's existing practices, and will result in greater consistency in the application of the ISO tariff.

GUOC Revisions

GUOC is a refundable payment made by the owner of a generating unit or aggregated generation facility to the AESO. The purpose of GUOC is to provide a long-term siting signal to generators to site in areas that would be most beneficial to load. GUOC must be paid before the commencement of construction of the facilities required to connect a generating unit or aggregated generation facility, and is refundable to the owner subject to the satisfactory operation of the generating unit determined under s 505.2 of the ISO rules, *Performance Criteria for Refund of Generating Unit Owner's Contribution*.

The current version of s 7.5(2) states that the GUOC refund period starts on January 1 following the initial contract capacity date specified in the SAS agreement. Under the AESO's proposal, the GUOC refund period starts on January 1 following the energization date specified in the GUOC notice that will be issued by the AESO under s 7.4(3). Interveners expressed concerns that the AESO's proposed revisions to s 7.5(2) would fix the start date for a project's GUOC refund period at an earlier date than is currently the case, thereby increasing the risk that a refund is forfeited if a generation project's actual energization date is delayed.

The AUC agreed that the proposed revisions would increase the risk that a GUOC refund is forfeited for some market participants. The AUC approved the alternative approach that the AESO proposed in its final argument, which provided that the energization date specified in the GUOC notice could be amended to align with any subsequent changes to the initial contract capacity date described in a SAS agreement, before the SAS agreement becoming effective, for generation projects that require a SAS agreement.

The AUC approved the proposed GUOC revisions as filed, with the following exception: the AUC directed the AESO to revise its proposed GUOC revisions, the ISO tariff, and any other documents that may be affected, in its compliance filing to this decision, to reflect the approach that the AESO provided in its argument.

***ATCO Electric Ltd. 2023-2025 General Tariff Application and Negotiated Settlement Agreement*, AUC Decision 27062-D01-2023**
Electricity - Rates

Application

As a transmission facility owner ("TFO"), ATCO Electric Ltd ("AE") recovers the costs of providing regulated electric transmission service through a transmission tariff that must be approved by the AUC. AE recovers the AUC-approved tariff amounts through the Alberta Electric System Operator ("AESO"), which collects the costs of transmission services provided to Alberta ratepayers.

AE applied for approval of a Negotiated Settlement Agreement ("NSA") regarding its 2023-2025 general tariff application ("GTA") and determination of three excluded issues.

Decision

The AUC approved the NSA. The AUC also approved the revenue requirements adjustments and the implementation of two new deferral accounts.

In respect of the excluded issues, the AUC: (i) approved the elimination of AE's Vegetation Management Reserve ("VMR"); (ii) approved modifications to AE's Variable Pay Program ("VPP") reserve; and (iii) disallowed true-up treatment of the $7.5 million undepreciated balance for the Jasper Palisades isolated generation plant.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 – ss 122, 132 and 135.

AUC Rule 018: *Rules on Negotiated Settlements*

Isolated Generating Unit and Customer Choice Regulation, Alta Reg 165/2003 – ss 20 and 22.

Pertinent Issues

The NSA

The AUC found that the NSA was negotiated under a fair process, is in the public interest, and results in just and reasonable rates. The AUC, therefore, approved the NSA.

Vegetation Management Reserve

In AUC Decision 20272-D01-2016, the AUC directed the implementation of a VMR due to the historic variance between forecast and actual vegetation management costs. AE requested that the VMR be discontinued because the reasons it was created no longer apply. Given that the evidence demonstrates that AE's forecasts have been more closely aligned with its actual vegetation management, the AUC found that it is reasonable to transition away from the VMR over the 2023-2025 test period. The AUC directed AE to maintain the VMR for 2023 but approved the elimination of the VMR beginning in 2024.

VPP Reserve

In AUC Decision 20272-D01-2016, AE was directed to establish a reserve account for its ratepayer-funded VPP. The reserve account mechanics were structured such that AE could not recover more than its approved VPP forecast amounts for a given year, nor carry over any unused VPP funds into a future test period. The VPP reserve was designed to address AE's need to fund VPP in support of its recruitment, retention, and operational performance goals while ensuring that any incentive to withhold VPP amounts to increase the utility's retained earnings was removed. AE requested two changes to its VPP reserve mechanics. It sought to: (i) exclude direct assigned capital VPP from the VPP reserve account; and (ii) include the revenue requirement amount related to the portion of capitalized VPP amounts in the reserve account, rather than the total amount of the non-direct assigned capital VPP forecast costs.

The AUC found that as a result of disaggregating the three components of the VPP (Operations and Maintenance, non-direct assigned capital and direct assigned capital), and given that variances between actual and approved capitalized expenditures are settled through the direct assigned capital deferral account, there is no need to track these costs through the VPP reserve. The AUC further noted that a reserve account is used to fund specific expenses that are paid out infrequently or at unpredictable intervals and are funded in advance through rates. The revenue requirement amount related to the portion of capitalized VPP amounts in the reserve account, rather than the total amount of the non-direct assigned capital VPP forecast costs, is the proper amount that should be reflected in the VPP reserve account. This is because these amounts reflect what AE has collected from ratepayers over each of the test periods towards the funding of AE's non-direct assigned VPP before ATCO

Electric distributes the VPP payout to its employees. The AUC approved the proposed changes to the mechanics of the VPP reserve.

True-up for Undepreciated Jasper Palisades Power Plant Switchgear Assets

As a result of an accounting error, from 2009 to 2020 certain switchgear assets forming part of AE's Jasper Palisades Power Plant ("JPPP") were depreciated at rates consistent with longer-lived transmission and general plant assets, rather than at a depreciation rate reflecting the expected shorter-lived assets. The accounting error resulted in a remaining undepreciated balance of $7.5 million at the time all JPPP assets were removed from service. AE submitted that it is just and reasonable for the AUC to approve the proposed $7.5 million one-time true-up of the switchgear assets in its 2023 tariff to provide AE with a reasonable opportunity to recover these costs.

The AUC denied the request and found that the correct undepreciated balance concerning the JPPP switchgear assets should be $0, permanently disallowing recovery of the undepreciated amount. The AUC found AE's explanation of how the undepreciated balance arose to be incomplete. The AUC found the error to have occurred due to an initial incorrect booking of the investment and thereafter an ongoing failure to discover and correct the mistake. The AUC held that there were reasonable opportunities for AE to discover and correct the mistake. The AUC further found that placing costs associated with AE's error on ratepayers provides the wrong incentives to AE and creates issues of intergenerational equity. The AUC, therefore, denied the true-up request.

***ATCO Gas and Pipelines Ltd. Franchise Agreement Renewal with the City of Cold Lake,* AUC Decision 28210-D01-2023**
Rates - Franchise Agreement

Application

ATCO Gas and Pipelines Ltd. ("ATCO Gas") applied for approval of a natural gas franchise agreement (the "Agreement"), including a franchise fee of 13 percent, with the City of Cold Lake for 10 years starting July 1, 2023.

Decision

The AUC approved the Agreement and the proposed franchise fee.

Applicable Legislation

AUC Rule 029: *Application for Municipal Franchise Agreements and Associated Franchise Fee Rate Riders*

Municipal Government Act, RSA 2000, c M-26.

Gas Utilities Act, RSA 2000, c G 5.

***Direct Energy Regulated Services 2023 Default Rate Tariff and Regulated Rate Tariff,* AUC Decision 27631-D01-2023**
Revenue Requirements - Non-Energy

Application

Direct Energy Regulated Services ("DERS") applied for approval of its default rate tariff ("DRT") and regulated rate tariff ("RRT") revenue requirements and non-energy charges for 2023.

Decision

The AUC approved the application in part.

Applicable Legislation

AUC Rule 003: *Service Quality Reporting for Energy Service Providers*

AUC Rule 023: *Rules Respecting Payment of Interest*

Electric Utilities Act, SA 2003, c E-5.

Default Gas Supply Regulation, Alta Reg 184/2003.

Gas Utilities Act, RSA 2000, c G 5.

Regulated Rate Option Regulation, Alta Reg 262/2005.

Pertinent Issues

Regulated and Competitive Split

DERS calculated a ratio, referred to as the regulated and competitive split, between its regulated and competitive retail businesses to establish the percentage of costs for services shared between DERS and Direct Energy Partnership that is allocated to DERS. The regulated and competitive split is used to determine specific costs associated with customer operations and impacts the labour revenue requirement. The calculation is based on the quarterly retail statistics report from the Market Surveillance Administrator (the "MSA retail statistics report").

The AUC denied the approach using the MSA retail statistics report as the basis to forecast the regulated and competitive split. The AUC held that the currently used method is not forward-looking. DERS uses data from one point in time as the basis for determining what site counts will be during the test period. However, the AUC determined that market conditions can result in significant shifts in the regulated and competitive split over a short period. Further, the MSA retail statistics reports are based on data from other utilities, not DERS. This data does not reflect facts specific to DERS' site counts.

The AUC found that DERS' internal site data is the most accurate and therefore recognized it as the primary source of data. The AUC found that using DERS' data best reflects market conditions and accurately allocates shared costs. The AUC, therefore, used DERS' internal data and found the regulated and competitive split to be 60.1 percent regulated.

Merchant Fees

The merchant fees are built into the non-energy charge paid by all of DERS' regulated customers regardless of their method of payment. DERS noted there had been a continued increase in the percentage of DERS customers who pay using credit cards and that the trend is forecast to continue. DERS applied for approval of a revised formula to forecast merchant fees. The updated formula includes distinct components based on data from a 36-month period and uses a multiplier to account for the differences in average bill amounts between those who pay by credit card and those who pay via other methods. DERS stated that its revised method will provide a better forecast of merchant fees because there is visibility into the drivers of the merchant fee such that recurring and one-time payments are separately accounted for. The AUC approved the revised method for forecasting merchant fees.

In addition, the AUC directed DERS to investigate the feasibility of passing on the associated merchant fees to customers electing to pay by credit card for the DRT in its next non-energy application.

Customer Information

The AUC disallowed DERS' customer information forecast of $224,047 and approved the amount of $84,000 for customer information consistent with the amounts approved for 2021 and 2022. The customer information costs are incurred as DERS provides and gathers information to and from customers. DERS submitted that for 2023 it expected to carry out a higher level of customer information activities. The AUC considered customer information costs to be discretionary and was not persuaded that a higher level of customer information activities is warranted given that DERS forecasted declining regulated sites for 2023.

Labour

DERS forecast an increase of 2.4 full-time equivalents ("FTEs") in 2023 to support its digital functions and customer communication roles.

The AUC denied DERS' requested five percent increase for labour inflation and approved three percent to account for labour inflation. The AUC determined that labour comparisons for DERS should be based on local Alberta data, specifically a local, non-union comparison. The AUC considered the Average Weekly Earnings and ATB's summary of 2022 increases to be representative figures and approved a rate labour inflation rate of three percent.

The AUC found that without a comparable digital and marketing group in DERS' 2020-2022 non-energy application, it was difficult to ascertain how much of the applied-for support functions were embedded in the Alberta Regulated Business team. Further DERS' application lacked a clear explanation of FTE shifts and department changes.

The AUC was not convinced that DERS' parent company would provide approximately six FTEs to support digital and marketing functions without a cost allocation to DERS. Given that DERS is projecting continued decreases in both the DRT and RRT regulated sites for 2023, the AUC found that DERS has adequate support in the digital and marketing team to carry on the duties described in DERS' application. Accordingly, the AUC denied the request for 2.4 incremental FTEs to support the digital and marketing team.

Bad Debt

The AUC denied DERS' bad debt expense forecast and directed DERS to recalculate its bad debt expense forecast. The AUC rejected the use of any percentage of revenue figures for 2020 and 2021 in determining the forecast bad debt expense component for 2023. While actual year-to-date percentages may be reflective of what the actual full-year percentages will be, no analysis was presented demonstrating that this is the case. The AUC noted that year-to-date actuals may not reflect the bad debt activities that take place at different times during the year. The AUC considered that full-year actual percentages should be used as the basis for the bad debt forecasts. The AUC found that the average of the corresponding actual bad debt expense as a percentage of revenue for the years 2017-2019 should be used to forecast the bad debt component for the DRT and the RRT for 2023. The AUC directed DERS to use the percentages for those years as reported in this application, in the compliance filing when forecasting the bad debt component of the total bad debt expenses for 2023.

The AUC denied DERS' proposed bad debt deferral account where bad debt expense would only be refunded to customers if it is lower than the AUC approved forecast. In this case, 75 percent would be refunded. If total bad expense exceeds the approved forecast 100 percent would be recovered from customers. Instead, the AUC approved a symmetrical deferral account such that if aggregate bad debt exceeds the revised forecast, 100 percent of the difference will be deferred to the account of customers; and if the aggregate debt is less than the revised forecast, 100 percent of the difference will be credited to customers.

In the interest of regulatory efficiency, the AUC approved the proposal to combine the balances in the DRT bad debt expense deferral account and the DRT late payment charge deferral account. The AUC also approved the combination of the amounts in the corresponding RRT accounts.

Other Matters

The AUC approved DERS' revisions to its terms and conditions of service including editorial changes and clarifications regarding practices, policies, and customer responsibilities to address the growing costs related to bad debt and unknown customers. The AUC directed DERS to make minor amendments to its updates and refile the documents in the compliance filing.

The AUC denied DERS' hearing reserve of $0.453 million for 2023. Instead, the AUC directed DERS to update the hearing cost reserve and hearing cost recovery amounts by updating the hearing costs to match DERS' cost claims in Proceeding 28082 in addition to excluding the costs for the 2024-2025 DRT and RRT application.

***Direct Energy Regulated Services Default Rate Tariff and Regulated Rate Tariff 2022 Rider C True-Up, and Bad Debt and Late Payment Charge Deferral Account Disposition,* AUC Decision 28138-D01-2023**
Electricity - Rates

Application

Direct Energy Regulated Services ("DERS") applied for approval of the disposition of its 2022 bad debt and late payment charge deferral accounts for its default rate tariff ("DRT") and regulated rate tariff ("RRT") and to recover $29,248 in under-collected 2022 Rider C revenues. DERS requested permission to recover a total of $4,373,252 from DRT and RRT customers in 2023.

Decision

The AUC approved deferral account balances and true-up balances for DERS. The AUC further approved DRT and RRT Rider C1 rates which would be in effect from June 1 to August 31, 2023. The AUC also approved amounts included in the monthly gas cost flow-through rate ("GCFR") for June to August 2023.

Applicable Legislation

Regulated Rate Option Regulation, Alta Reg 262/2005.

Pertinent Issues

DERS submitted its bad debt and late payment charge deferral account balances under the negotiated settlement approved in Decision 26207-D01-2021 for approval. The AUC determined that DERS correctly calculated the deferral account balances for 2022 and approved the collection of $3,283,326 and $1,060,677 for the 2022 DRT and RRT bad debt and late payment charge deferral account balances, respectively.

DERS requested in this proceeding to add the 2022 DRT and RRT Rider C true-up balances to the respective DRT and RRT deferral account balances to be recovered through the 2023 rider. DERS submitted that it under-collected $5,698 from DRT customers and $23,550 from RRT customers resulting from the 2022 Rider C disposition and argued that combining the applications in one proceeding would be more efficient. The AUC approved the recovery of the applied-for balances and the addition of the balances to the 2022 bad debt and late payment charge deferral accounts for disposition in 2023.

To recover the DRT and RRT bad debt and late payment charge deferral account balances, DERS proposed to separate RRT deferral account balances between energy and non-energy, with the energy amount allocated to each rate class using load allocation percentages, and the non-energy amount allocated to each rate class using the number of bills allocation percentages. The DRT deferral account balances were also separated between energy and non-energy. The entire DRT energy amount will be collected through the GCFR. The DRT non-energy amount is allocated to each rate class, using the number of bills allocation percentages for each class in 2022. The AUC approved the recovery or refund as proposed by DERS.

DERS proposed Rider C1 was developed using a forecast of DRT and RRT customer totals over the collection period. The AUC found that a summary of the 2023 Rider C1 revenues would be beneficial to assess whether future rate riders are required. Accordingly, and as proposed by DERS, the AUC directed DERS to file an application that included the actual RRT and DRT Rider C1 revenues and refunds by rate class, the corresponding approved balances, and the resulting differences.

***ENMAX Energy Corporation 2022-2024 Non-Energy Regulated Rate Option Tariff Negotiated Settlement Agreement,* AUC Decision 27714-D02-2023**

Rates - Negotiated Settlement

Application

ENMAX Energy Corporation ("EEC") applied for approval of a Negotiated Settlement Agreement ("NSA") concerning its 2022-2024 non-energy regulated rate option tariff application.

Decision

The AUC found that the NSA reached between EEC and interveners including the Utilities Consumer Advocate and the Consumers' Coalition of Alberta was negotiated under a fair process, is in the public interest, and would result in just and reasonable rates. The AUC approved the NSA as filed.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1.

Regulated Rate Option Regulation, Alta Reg 262/2005.

AUC Rule 018: *Rules on Negotiated Settlements*

Pertinent Issues

The AUC has previously considered negotiated settlements in rate cases including where, as here, there was unanimous agreement.

Because no interested party to the NSA represents all stakeholders, the AUC noted the negotiated settlement process ("NSP") and NSA do not replace a full and informed review by the AUC as to what is in the overall public interest. Because EEC agreed to an NSP, negotiated with parties representing ratepayers, executed the NSA, and applied to the AUC for approval of the NSA, the AUC considered that the NSA satisfied EEC's interests. The AUC consequently assessed the NSA only from the perspective of ratepayers.

The agreed-to NSA would lead to reductions to EEC's applied-for revenue requirement in communications, billing and customer care, salary escalators, non-salary escalators, and internet technology cost allocation adjustment cost categories. Despite these reductions, the AUC noted that the negotiated administration charge would increase in 2023 and 2024 relative to the originally applied-for rates. The AUC understood that this is a consequence of a decrease in site counts, as compared to what was initially forecast by EEC in the original applied-for rates.

The AUC approved the increase. It accepted EEC's explanation that the increase results from the practice of updating forecasts to use the most recent site-count actuals available. This was determined to be consistent with the AUC's practice in previous proceedings and reflects an interest in relying on the best available information when setting rates.

***ENMAX Energy Corporation 2023-2024 Energy Price Setting Plan,* AUC Decision 27495-D01-2023**

Electricity- Rates

Application

ENMAX Energy Corporation ("EEC"), as a regulated rate option ("RRO") provider, applied for approval of its 2023-2024 energy price setting plan ("EPSP").

Decision

The AUC determined that the application from EEC was satisfactory but did not approve certain aspects of the 2023-2024 EPSP as applied for.

Applicable Legislation

AUC Rule 001: *Rules of Practice - ss 30, 76(1)(e)*.

Regulated Rate Option Regulation, Alta Reg 262/2005.

Pertinent Issues

At the time of its application, EEC was operating under its approved 2019-2022 EPSP which adopted two new processes for determining the RRO rate. The new processes are a descending clock auction and an alternative commodity risk compensation ("CRC") calculation.

The AUC approved a change to EEC's letter of credit ("LOC") rate but required EEC to update the proposed wording to include clarification of when updates to the LOC rate will occur. The LOC rate is used as an input in calculating the monthly Alberta Electric System Operator ("AESO") collateral costs and the monthly natural Gas Exchange ("NGX") collateral costs, as described in the 2023-2024 EPSP. The AUC denied the recommendation from the Utilities Consumer Advocate ("UCA") that any changes to the LOC rate are filed with the AUC for approval of part of EEC's monthly energy rate filings, along with support for any changes. The AUC determined that this step would be unnecessary and inefficient.

The AUC denied the request from EEC to change the method for calculating and reporting the monthly NGX collateral costs in the illustrative energy charge workbook. The approved illustrative energy charge workbook includes two inputs for the calculation of the NGX collateral costs: the posted collateral amount and the LOC rate. The product of these two inputs is divided by 12 to calculate the forecast monthly NGX collateral costs.

EEC proposed to add a line item described as "prior month adjustment" to the illustrative energy charge workbook and to use the corresponding amount as another input in calculating the forecast monthly NGX collateral costs. The AUC denied the request as the use of the term "prior month adjustment" implies a true-up for activities from a previous month. Amounts for the current month's forecast that include differences in costs between the previous month's actual and forecast costs are not permitted under the *Regulated Rate Option Regulation*. The AUC found that the prior month adjustment is not required as a specific line item, because any changes in the posted collateral amount during the forecast month can be incorporated into the forecast posted collateral amount, with the resulting forecast being a daily average balance.

The UCA submitted that the net CRC collected by EEC effectively represents a profit, and if it is included in the energy return margin calculation, EEC is effectively receiving a return on what already represents a profit component. Accordingly, the UCA suggested that the net CRC be removed from the energy revenues included in the calculation of EEC's energy return margin. The AUC determined that including the net CRC in the calculation of the return margin would not be fair to customers. The inclusion would result in a commodity profit component being included in the return margin when a positive amount was already earned for commodity risk.

The CRC is a legislated requirement under the *Regulated Rate Option Regulation* that is meant to provide financial compensation for the risk that an RRO provider faces due to uncertainties associated with the quantity of energy to be supplied or the price at which the energy is procured. When calculating the energy return margin, the CRC is included in the energy revenues upon which EEC's return markup is applied. The AUC accepted the recommendation from the UCA to remove the net CRC from the energy revenues upon which EEC's return markup is applied.

***EPCOR Distribution & Transmission Inc 2023 System Access Service Rate Update*, AUC Decision 28133-D01-2023**

Electricity - Rates

Application

In this application, EPCOR Distribution & Transmission's ("EDTI") requested approval to update its 2023 System Access Service ("SAS") rates effective July 1, 2023, to align its SAS cost-of-service model with the changes to the Alberta Electric System Operator ("AESO") demand transmission service ("DTS") rate components. EDTI forecast its total SAS revenue requirement for the period July 1, 2023, to December 31, 2023, to be $144.34 million, excluding direct connect ("DC") customers, which customers continue to have the AESO transmission charges directly flowed through to each site.

Decision

The AUC approved EDTI's application for an update to its 2023 SAS rates, effective July 1, 2023, finding that the calculations were reflective of the approved AESO tariff and consistent with corresponding AUC approvals.

Applicable Legislation

Regulated Rate Option Regulation, Alta Reg 262/2005.

Pertinent Issues

EDTI's SAS rates are designed to recover charges paid by EPCOR to the AESO for access to the transmission system. In addition to recovering AESO charges through SAS rates, EDTI reconciles variances between the forecast SAS revenues and forecast AESO costs every quarter through its AESO demand transmission service ("DTS") deferral account Rider K. Any residual variances between SAS revenues and DTS costs are reconciled in the annual transmission access charge deferral account true-up process to ensure that the revenues collected through its transmission access charges in a year recover the AESO tariff charges that EDTI pays to the AESO in that year. The AESO charges are flowed through dollar-for-dollar to EPCOR's customers, which means that the utility does not assume any volume or price risk but also does not earn any return.

***General Land & Power Corp. and AltaLink Management Ltd. Sollair Solar Energy Project and Connection,* AUC Decision 27582-D01-2023**

Solar Power - Facilities

Applications

General Land & Power Corp. ("GL&P") applied for approval to construct and operate the 75-megawatt Sollair Solar Energy Power Plant, and the associated Sollair 1055S Substation (the "Project"). The Project will be constructed on 476 acres of cultivated freehold land adjacent to the north boundary of the City of Airdrie.

AltaLink Management Ltd. ("AML") applied for approval to construct and operate a new 138-kilovolt Transmission Line 688BL and alter Transmission Line 688L to connect the Project to the Alberta Interconnected Electric System.

Decision

The AUC approved the applications from GL&P and AML, subject to certain conditions.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37.2 - s 17.

Hydro and Electric Energy Act, RSA 2000, c H-16 - s 11, 14, 15, 18 and 19.

AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*.

AUC Rule 012: *Noise Control*

Historical Resources Act, RSA 2000, c H-9.

ISO Rules Section 501.3 *- Abbreviated Needs Approval Process*

AUC Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*

***Journey Energy Inc. Gilby Thermal Power Plant,* AUC Decision 27860-D01-2023**
Thermal Power - Facilities

Application

Journey Energy Inc. applied for approval to construct and operate the 15.5-megawatt Gilby Thermal Power Plant (the "Power Plant") and connect the Power Plant to FortisAlberta Inc.'s 25-kilovolt electric distribution system. The Power Plant will be located within the boundary of the Gilby Sweet Gas Processing Plant, operated by Journey Energy Inc. 10 kilometers southwest of Rimbey. The area of the Gilby Sweet Gas Processing Plant would expand by approximately 0.56 hectares.

Decision

The AUC approved the application for permission to construct and operate the Power Plant.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37.2.

Hydro and Electric Energy Act, RSA 2000, c H-16.

Historical Resources Act, RSA 2000, c H-9.

AUC Rule 001: *Rules of Practice*

AUC Rule 012: *Noise Control*

Alberta Ambient Air Quality Objectives and Guidelines

***Millar Western Forest Products Ltd. and Canfor (Whitecourt) Forest Products Ltd. Millar Western Pulp Industrial Complex Power Plant Alteration and Industrial System Designation*, AUC Decision 28072-D01-2023**
Electricity - Facilities

Application

Millar Western Forest Products Ltd. ("Millar Western") applied for approval of a minor alteration to its existing biogas power plant. Millar Western and Canfor (Whitecourt) Forest Products Ltd. ("Canfor") also applied for approval of an industrial system designation ("ISD") that encompasses all electric facilities, including the biogas power plant at the existing Millar Western Pulp Industrial Complex (the "Power Plant").

Decision

The AUC approved the applications from Millar Western and Canfor.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37.2 - s 17.

Hydro and Electric Energy Act, RSA 2000, c H-16 – ss 4, 11 and 12.

AUC Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*.

Environmental Protection and Enhancement Act, RSA 2000, c E-12.

Electric Utilities Act, SA 2003, c E-5.1.

Pertinent Issues

Millar Western applied to amend the existing power plant approval to reflect the 0.8-megawatt increase in the total nominal capacity of the Power Plant. The AUC was satisfied that the proposed changes are minor, no person is directly and adversely affected by the proposal and no significant adverse environmental impact would be caused by the alteration. The AUC, therefore, approved the alterations.

Plant Alterations

The Millar Western Pulp Industrial Complex (the "Complex") consists of Millar Western's pulp mill and existing biogas power plant, a sawmill sold to Canfor in 2022, and associated support activities for both operations. The electric facilities that serve the Complex include a power plant and 13.8-kilovolt cables, transformers, and circuit breakers. Millar Western and Canfor requested that the AUC issue an order designating the electric facilities at the Complex as an industrial system.

Industrial System Designation

The Complex is connected to the Alberta Integrated Electric System ("AIES") through a substation within the site of the Complex. Millar Western and Canfor will continue to import electricity from the AIES to provide for approximately three percent of the load requirement of the Complex. The applicable wires tariff charges would also continue to be paid. The AUC was satisfied that the ISD would not be used to avoid system costs.

The AUC concluded that, taking into account the applicable principles and criteria for an ISD, Millar Western, and Canfor's proposal substantially meets the principles and criteria for an ISD and that it demonstrates significant and sustained increased efficiency in the industrial operations. The AUC granted an ISD for the electric system at the Complex.

***Wheatland Industries Ltd. Decision on Threshold Issue Application for Review of Decision 26395-D01-2021 Kirkcaldy Solar Energy Centre,* AUC Decision 28015-D01-2023**
Review and Variance - Procedural

Application

On February 10, 2023, Wheatland Industries Inc. ("Wheatland") applied for a review and variance of Decision 26395-D01-2021 issued on November 12, 2021, which decision approved the construction and operation of the Kirkcaldy Solar Energy Centre (the "Decision").

Decision

The AUC denied the application from Wheatland for review and variance of Decision 26935-D01-2021.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37.2.

Code of Conduct Regulation, Alta Reg 58/2015.

AUC Rule 016: *Review of Commission Decisions*

Pertinent Issues

The AUC stated that s 3 of AUC *Rule 016: Review of Commission Decisions* ("*Rule 016*") provides that a person who is directly and adversely affected by a decision may apply for a review of the decision within 30 days of the decision being issued and that the AUC may authorize that an application for review of a decision be filed outside of the 30-day period. Under s 3 of *Rule 016*, a person who was not a party to the proceeding that gave rise to the decision must obtain leave (permission) of the AUC before applying for review.

The AUC found that Wheatland was not a party to Proceeding 26395, its application for review was filed approximately 15 months after the issuance of the Decision, and that Wheatland did not request leave to file its application for review, nor did it seek the AUC's authorization to file its application outside of the 30-day period.

The AUC noted that if a person did not participate in the original proceeding, the review panel must determine in the review proceeding whether that person has demonstrated that he or she is directly and adversely affected by the decision. A person is directly and adversely affected if he or she meets the two-part test established by the Alberta Court of Appeal: a person must assert a right that is recognized by law (legal test); and a person must provide enough information to show that a decision has the potential to directly and adversely affect the person's right, claim or interest (factual test).

Wheatland asserted that its right to reject unprofessional and deceitful manipulation of the public trust anywhere and, at any time it becomes apparent, and its right to a fully disclosed, public proceeding was affected. It submitted that the latter was directly and adversely affected because (i) of "unacceptable deviation and omission of obligatory process" in the original proceeding, (ii) the original proceeding "in no way offered candid disclosure of critical project knowledge nor revealed or adequately portrayed the horrendous adverse consequences of the upsizing of the project", and (iii) the original proceeding "was not executed in good faith."

The AUC found that the rights asserted by Wheatland are procedural in nature, which are only triggered if a person has a substantive right that is directly and adversely affected by the Decision. Since Wheatland has asserted no such substantive right, the review panel determined that the Wheatland did not demonstrate that it meets the test for standing in s 3 of *Rule 016*, which requires the person to be directly and adversely affected. Consequently, the AUC denied leave to Wheatland to proceed with its review application.

Notwithstanding the denial of leave to Wheatland, the AUC also considered whether to review the Decision on its own motion under s 2 of *Rule 016* and concluded that there were no exceptional or extraordinary circumstances that would warrant a review of the Decision.