REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA ENERGY REGULATOR

***Reminder of Closure Spend Reporting Requirements,* AER Bulletin 2022-36**
Oil and Gas - Closure Spending

Under *Directive 088: Licensee Lifecycle Management,* all licensees with inactive inventory are required to meet an annual mandatory closure spend target. Under this directive, each licensee must report to the AER all its 2022 closure activities and closure spends to OneStop by March 31, 2023.

The AER strongly recommends that licensees begin their reporting as soon as possible to ensure they can resolve discrepancies or other issues while still meeting the deadline.

Under s. 3.6 of *Manual 023: Licensee Lifecycle Management*, licensees can update all costs numerous times for 2022. The most recent submission overwrites any prior submissions. The AER will not consider closure spending reported after the 2022 reporting deadline.

ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator 2023 Independent System Operator Tariff Update, AUC Decision 27777-D01-2022

Electricity - Rates

Application

The Alberta Electric System Operator ("AESO") requested approval of:

(a) updated 2023 rate calculations; and

(b) proposed 2023 independent system operator ("ISO") tariff rates for demand transmission service ("DTS"), Fort Nelson demand transmission service ("FTS"), demand opportunity service ("OTS"), export opportunity merchant service ("XOS"), primary service credit ("PSC"), supply transmission service, Rider J and generating unit owner's contribution ("GUOC").

Decision

The AUC approved the AESO's request for the 2023 update to the ISO tariff, including the proposed changes to the GUOC rates and the annual process to update GUOC rates.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 - s 14(3).

Pertinent Issues

Decision 2010-606, in which the AUC approved the AESO's proposal to file major tariff updates in multi-year intervals and much simpler updates on an annual basis, sets out that the annual ISO tariff updates must consist of three components.

The update filing is required to include an annual revenue requirement update using the wires cost forecast methodology approved in Decision 2010-606 and updated in Decision 22093-D02-2017, plus forecasts for ancillary services costs, losses costs and administration costs approved by the AESO's board for the forecast year.

The update must also include revised rate levels for each AESO rate calculated from the forecast revenue requirement and forecast billing determinants using rate calculations and the rate design approved in the most recent comprehensive tariff application.

To calculate the 2023 rates, the AESO used the 2023 forecast revenue requirement, the functionalization and classification of wires costs and the point-of-delivery costs function approved for 2020, and the 2023 forecast billing determinants prepared by the AESO.

The final component of the update requires annual updates to investment amounts approved in the most recent comprehensive tariff, reflecting an escalation factor based on the most recent Conference Board of Canada's forecast of Alberta's Consumer Price Index ("CPI").

The AESO also proposed updates to the GUOC rates for 2023 using the approved method. The AESO developed the proposed 2023 GUOC rates and separated the rates by region depending on the presence of near-term generation integration capability in the region and the associated development interest

The AUC was satisfied that the revenue requirement forecast was prepared following the approved method.

The AUC found that the AESO's use of its 2021 Long-term Outlook, which forecasts relatively flat load growth in 2023, as the basis to determine 2023 billing determinants in the tariff update was reasonable and approved the applied-for 2023 ISO tariff rates.

The AUC was satisfied that the AESO's submission of maximum investment level amounts escalated by a factor of 1.0979, based on a composite of specified recent inflation indices, is consistent with the rate calculation methodology previously approved by the AUC.

Finally, the AUC approved the applied-for GUOC rates.

Apex Utilities Inc. 2023 Cost-of-Service Compliance Filing and 2023 Rates, AUC Decision 27685-D01-2022
Gas - Rates

Application

In this decision, the AUC considered whether Apex Utilities Inc. ("AUI") complied with AUC directions made in AUC Decision 26616-D01-20221 regarding AUI's Cost-of-Service ("COS") review ("*COS Review Decision*") and reviewed AUI's resulting 2023 distribution rates.

Decision

The AUC determined that AUI complied with its directions from the *COS Review Decision*, other than failing to remove the true-up (timing) adjustment for shared corporate services costs. The AUC directed AUI to remove the $190,000 adjustment at the time of other true-ups to 2023 rates.

The AUC approved AUI's 2023 distribution rates on an interim basis. The AUC also approved AUI's 2023 Special Charges Schedule, Retailer Distribution Services Rules, and AUI's request to finalize its 2021 interim performance-based regulation ("PBR") rates based on the calculation of its 2021 going-in revenue and K-bar amounts.

Applicable Legislation

Natural Gas Billing Regulation, AR 185/2003.

Pertinent Issues

Compliance with Decision 26616-D01-2022

In the *COS Review Decision,* the AUC directed AUI to use the TriSummit Utilities ("TSU") shared corporate services costs at a 2021 forecast level and then normalize that forecast to 2023 dollars, using approved inflation and customer growth escalation factors. In addition to performing the directed adjustments, AUI removed $190,000 of credits listed as a true-up (timing) from the 2021 forecast shared corporate services costs allocated to it by TSU. AUI explained that it excluded costs from the true-up (timing) cost category because these amounts represent differences between billed and actual 2020 costs that were not accrued in 2020. AUI indicated that while these differences are recognized in the 2021 year for accounting purposes, they represent part of the cost of services provided in 2020 and not 2021. The AUC decided not to allow AUI proposed adjustment. Just as there was a timing adjustment in 2021 for differences between billed and actual 2020 costs, presumably, there was or will be an adjustment in 2022 for differences between billed and actual 2021 costs. Following AUI's logic, the adjustment for (expected) differences between billed and actual 2021 costs should have been added to the 2021 forecast costs to arrive at a more precise number for that year.

2023 Distribution Rates

AUI noted that an unadjusted allocation of revenue requirement to each rate class based on the current Phase 2 allocations would increase the delivery rates of Rate 4/14 (Irrigation) customers by 39.9 percent and increase the bill impact, excluding commodity costs by 29 percent. To mitigate rate shock and consider affordability to its Rate

4/14 customers, AUI allocated $50,000 from Rate 4/14 customers to Rate 3/13 (demand) customers to increase the rate for Rate 4/14 customers to 10 percent in delivery rates and 8.7 percent in bill impact excluding commodity costs. Rate 3/13 was identified as the offsetting rate class, as it will see a decrease in rates for 2023.

The AUC found that AUI's schedules and 2023 rate calculations were accurate and reasonable. The AUC approved AUI's 2023 rates on an interim basis.

***ATCO Electric Ltd. 2023 Cost-of-Service Compliance Filing and 2023 Rates,* AUC Decision 27672-D01-2022 and 27672-D02-2022**
Electricity - Rates

Application

In Decision 27672-D01-2022 ("*Decision 1*"), the AUC directed ATCO Electric Ltd. ("AE") to make certain adjustments to its 2023 revenue requirement, 2023 rates, options, riders and rate schedules and to provide updated schedules, including rate calculations. In Decision 27672-D02-2022 the AUC, having reviewed AE's filing made pursuant to *Decision 1*, provided its reasons for the determinations made in *Decision 1*.

Decision

The AUC approved AE's application with conditions.

Applicable Legislation

AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

AUC Rule 023: *Rules Respecting Payment of Interest*.

Pertinent Issues

The AUC required adjustments to the applied-for revenue requirement, rates, options, riders and rate schedules. The AUC directed AE to update only the mechanistic portion of its forecasts. The AUC denied adjustments for any portion of the forecast above the three-year average.

CIS Replacement Program

AE updated the in-service date of its Customer Information System ("CIS") Replacement Program because of delays resulting from several factors, including the requirement for rigorous testing across all levels. The City of Calgary ("CG") raised issues with the change of the in-service date of the CIS Replacement Program. CG stated that if $55.5 million of the forecast project costs ($70.1 million) have already been booked as of September 2022, then only $14.6 million of costs remain to be incurred in 2023. AE responded that the total forecast spend was $68.3 million, not $70.1 million.

The AUC found AE's updated 2023 forecast revenue requirement, reflecting the shift of capital additions for the CIS replacement program to 2023, to be reasonable.

***ATCO Electric Ltd. 2023 Interim Transmission Facility Owner Tariff,* AUC Decision 27835-D01-2022**
Electricity - Rates

Application

ATCO Electric Ltd. ("AE") applied to the AUC for approval of a 2023 transmission facility owner tariff ("TFO") on an interim refundable basis.

Decision

The AUC approved the request from AE for a 2023 interim monthly TFO tariff of $55,545,333, effective January 1, 2023.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 - ss 37, 119 and 124(2).

Pertinent Issues

The AUC applied its two-part test to evaluate the interim rate application by considering quantum and need factors in the first step and the public interest in the second.

The applied-for interim TFO tariff is five percent or $34.2 million lower than the 2022 final TFO tariff, primarily due to the proposed discontinuation of the future income tax collection. At the time of this application, final rates for 2023 were not determined. The AUC found it reasonable to establish interim rates until AE's 2023-2025 general tariff application was considered and 2023 rates approved.

The AUC was satisfied that the approval of AE's applied-for 2023 interim TFO tariff would assist AE in continuing to meet its financial obligations and ensure safe utility operations while also providing customers rate stability and intergenerational equity. The interim TFO tariff was approved, subject to a true-up after the AUC approves AE's final 2023-2025 revenue requirement in Proceeding 27062.

***ATCO Gas 2023 Cost-of-Service Compliance Filing and 2023 Rates*, AUC Decision 27684-D01-2022**
Gas - Rates

Application

In this decision, the AUC considered whether ATCO Gas complied with all directions issued in Decision 26616-D01-20221 and reviewed ATCO Gas's resulting 2023 distribution rates.

Decision

The AUC determined that ATCO Gas complied with all directions from Decision 26616-D01-2022. As a result, the AUC approved the resulting 2023 forecast revenue requirement. The AUC approved ATCO Gas' 2023 distribution rates set out in this decision on an interim basis. The AUC further approved ATCO Gas' 2023 schedule of non-discretionary charges and the updated Producer Terms and Conditions.

Applicable Legislation

AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

AUC Rule 023: *Rules Respecting Payment of Interest*.

ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. 2023 Transmission Service Charge (Rider T), **AUC Decision 27752-D01-2022**
Gas - Rates

Application

ATCO Gas, a division of ATCO Gas and Pipelines Ltd. ("ATCO Gas"), filed an application with the AUC requesting approval of an update of its 2023 transmission service charge rider ("Rider T") rates for 2023, effective January 1, 2023. The AUC approved the current ATCO Gas Rider T rates in Decision 26592-D01-2021. The current application accounts for changes to NOVA Gas Transmission Ltd. ("NGTL")'s rates.

Decision

The AUC approved ATCO Gas' 2023 Rider T rates, effective January 1, 2023.

Applicable Legislation

Bulletin 2015-09: *Performance standards for processing rate-related applications*.

AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

Gas Utilities Act, RSA 2000, c. G-5.

Pertinent Issues

ATCO Gas flows the rates charged by the transmission service provider, NGTL, to its customers through Rider T. Rider T is used to collect forecast transmission costs and to refund or collect any differences between the prior year's forecast and actual costs.

The AUC found that the implementation of the updated 2023 Rider T, in isolation, results in small rate increases for all rate groups for both ATCO Gas North and ATCO Gas South. When considered together with rate changes applied for in Proceeding 27684, where ATCO Gas's 2023 distribution rates are considered, the proposed Rider T rates' effect is a limited offset of otherwise decreasing charges. Given the flow-through nature of Rider T charges and the fact that these rate changes are relatively small and do not result in rate shock, the AUC found that the estimated rate impact of January 1, 2023, Rider T was reasonable for all rate classes.

AUC Residential Standards of Service and Maximum Investment Levels, **AUC Decision 27658-D01-2022**
Maximum Investment Levels - Cost-of-Service Year

Application

The AUC considered the 2023 Maximum Investment Levels ("MILs") for the distribution facility owners ("DFOs") ENMAX Power Corporation ("EPC"), FortisAlberta Inc. ("FortisAB"), EPCOR Distribution & Transmission Inc. ("EDTI") and ATCO Electric Ltd. ("AE").

The AUC established this proceeding in two phases: (i) the AUC would set 2023 MILs, and (ii) the AUC would hold a more extensive proceeding re-examining the principles underlying MILs for subsequent years. This decision dealt with the first phase.

Decision

The AUC set the 2023 MILs on a final basis and determined that the value of 2023 MILs for each DFO will be set based on an escalation of 2022 approved MILs by the inflation escalator of 2.68 percent.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 - ss 1, 5, 101, 102, 105 and 120.

Pertinent Issues

A MIL is a maximum amount a DFO can contribute toward the cost of connecting a new customer to its system. Any remaining connection costs fall to the individual customer as a customer contribution. MILs are set amounts approved as part of each DFO's terms and conditions of service.

The AUC granted developers full participatory rights in this proceeding but found that they are not "customers" under *Electric Utilities Act* ("*EUA*"). The text of the definition of "customer" strongly supports the conclusion that the term "customer" only contemplates end-use customers who consume electric energy. Even though individual developers are responsible for the construction of electric utility infrastructure inside the new residential developments within their service areas, after construction is complete, the developer passes ownership of this infrastructure back to the DFO.

The AUC set the DFOs' 2023 MILs by escalating its 2022 approved MILs by the inflation escalator consistent with the approvals in the Cost-of-Service ("COS") rebasing applications. The AUC set the 2023 MILs on a final basis to avoid an administrative burden and uncertainty, as parties would not know how costs would be allocated under interim MILs when they initiated a project.

The AUC set all DFOs COS inflation escalators at 2.68 percent as approved in Decision 26615-D01-2022 for FortisAB. The AUC determined that this was reasonable because all DFOs considered in this proceeding face similar inflationary pressures and have similar salary escalations for 2023.

***Balancing Pool Application for an Order Permitting the Sharing of Records Not Available to the Public Regarding the Chappice Lake Solar Project,* AUC Decision 27774-D01-2022**
FEOC Regulation - Markets

Application

The Balancing Pool ("BP") filed an application for the preferential sharing of records that are not available to the public relating to the 13.9-megawatt Chappice Lake Solar Project between the Balancing Pool, Chappice Lake GP Inc. ("Chappice Lake GP"), Chappice Lake Limited Partnership ("Chappice Lake LP"), Elemental Energy Inc. ("EEI"), Elemental Energy Renewables Inc. ("EERI") and URICA Energy Real Time Ltd ("URICA").

Decision

The AUC granted the application to permit the sharing of records pertaining to the Alberta energy market.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37.2 - s 39(2)(a)(vi).

Electric Utilities Act, SA 2003, c E-5.1 - s 6.

Fair, Efficient and Open Competition Regulation, Alta Reg 159/2009 - ss 2, 3, and 5(5).

Canadian Utilities Limited Application for the Amalgamation of ATCO Power (2010) Ltd., Barlow Solar Park Ltd. and Deerfoot Solar Park Ltd., AUC Decision 27872-D01-2022
Power - Land

Application

Canadian Utilities Ltd. ("CUL"), ATCO Power 2010 ("ATCO Power"), Barlow Solar Park Ltd. ("Barlow") and Deerfoot Solar Park Ltd. ("Deerfoot"), collectively, (the "applicants") filed for approval to amalgamate ATCO Power, Barlow and Deerfoot.

Decision

The AUC approved the application to amalgamate ATCO Power, Barlow and Deerfoot.

Applicable Legislation

Alberta Business Corporations Act, RSA 200, c B-9.

Gas Utilities Act, RSA 2000, c G-5 - ss 26 and 27.

Public Utilities Act, RSA 2000, c P-45 - ss 101, 102 and 109.

Pertinent Issues

ATCO Power will amalgamate with each of Barlow and Deerfoot through a short-form vertical amalgamation. After that, it shall continue as ATCO Power (described in ATCO Power 2010 Amalco). ATCO Power 2010 Amalco will be a direct, wholly-owned subsidiary of CUL.

The AUC noted that the amalgamation involves the vertical amalgamation of three existing non-regulated entities. The AUC also noted that it would not result in any financial harm to the customers. As a result, the AUC found that the no-harm test requirement for amalgamation has been satisfied.

***Direct Energy Regulated Services 2023 Interim Default Rate Tariff and Regulated Rate Tariff,* AUC Decision 27868-D01-2022**
Gas - Rates

Application

Direct Energy Regulated Services ("DERS") applied for approval of interim rates, effective January 1, 2023, including:

(a) Default Rate Tariff ("DRT") and Regulated Rate Tariff ("RRT") rate schedules;

(b) Continuation of the DRT return margin charge of $0.053/gigajoule ("GJ"), approved in Decision 26207-D01-2021;

(c) Continuation of the DRT energy-related charge of $0.021/GJ, approved in Decision 26207-D01-2021; and

(d) Continuation of the monthly amount of $34,499 for DRT energy-related labour, approved in Decision 26207-D01-2021.

Decision

The AUC approved DERS' 2023 interim DRT and RRT non-energy rates, which are the same as the existing 2022 rates.

Applicable Legislation

Regulated Rate Option Regulation, AR 62/2005.

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

Pertinent Issues

DERS requested the continuation of its 2022 final DRT and RRT non-energy rates, as well as the continuation of its 2022 final DRT return margin charge of $0.053/GJ, the 2022 final charge of $0.021/GJ for certain DRT energy costs, and the 2022 final monthly amount of $34,499 for labour costs associated with DRT energy procurement, all on an interim basis beginning January 1, 2023. Because the AUC previously tested and approved these amounts, the AUC found DERS' request to continue these amounts for 2023, on an interim basis, reasonable and in the public interest. These amounts will be adjusted upon final approval of DERS' 2023 DRT and RRT non-energy application.

***Direct Energy Regulated Services 2023-2025 Energy Price Setting Plan,* AUC Decision 27562-D01-2022**
Electricity - Rates

Application

Direct Energy Regulated Services ("DERS") applied for approval of its 2023-2025 energy price setting plan ("EPSP"). DERS is a regulated rate option ("RRO") provider and performs the electricity-regulated rate tariff functions in the service territory of ATCO Electric Ltd.

Decision

The AUC did not approve DERS' 2023-2025 EPSP as filed. DERS was directed to make changes to its 2023-2025 EPSP and refile it. DERS was further directed to submit a compliance filing reflecting the AUC's findings and directions.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 - s 104.

Regulated Rate Option Regulation, AR 262/2005 - s 6.

AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

Pertinent Issues

DERS submitted that the 2023-2025 EPSP is materially consistent with the previous EPSP. DERS did, however, propose changes to the confidential procurement protocol as well as other changes to the non-confidential provisions of the EPSP.

The Utilities Consumer Advocate ("UCA") raised concerns with changes to the confidential procurement protocol of the 2023-2025 EPSP. The AUC approved two confidential changes and the following non-confidential changes as filed:

(a) clarifications of the number of "total target volume blocks" used in the calculation of the monthly energy rates in situations where the total target volume blocks have been over-procured because of changes in the load forecast;

(b) annual updates to the seasonal multipliers; and

(c) annual updates to the energy return margin in July with data from DERS' most recent Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filing.

Excluding the Net Commodity Risk Compensation from the Revenues on Which the Energy Return Margin Is Calculated

The UCA recommended that the net commodity risk compensation be excluded from the revenues on which the energy return margins are calculated. As part of the 2023-2025 EPSP, DERS proposed to update the after-tax energy return margin that would be in place for the January 2023 to June 2023 rate months using the revenues and load for 2021, as reported in DERS' Rule 005 reporting for 2021. The UCA did not object to DERS' proposal to update the after-tax energy return margins using the information for 2021 and subsequent years. However, it recommended that DERS be directed to remove its net commodity risk compensation when calculating the amounts on which the energy return margins is calculated. It submitted that the net commodity risk compensation effectively represents a profit component. If it is included in the after-tax energy return margin calculation, DERS effectively receives a return on what already represents a profit component.

The AUC approved the methodology proposed by DERS to calculate the return margin for the 2023-2025 EPSP, with the exception of the net commodity risk compensation, and approved DERS' request to update the calculation of the return margin on an annual basis as part of the 2023-2025 EPSP, with such updates included as part of the filing of the monthly energy rates for July 2023, July 2024 and July 2025. The AUC directed DERS to remove the net commodity risk compensation, which is calculated as the difference between the commodity risk compensation and the commodity gains/(losses), from the revenues used in the DERS' return margin calculation. The AUC noted that this would allow for a clearer separation of the net commodity risk compensation for DERS' financial risks in providing RRO service from the return margin. DERS, as part of the compliance filing, was also directed to recalculate and submit the initial return margin to be used in the 2023-2025 EPSP by excluding the net commodity risk compensation for 2021 and including details of the recalculation.

***Enforcement Staff of the AUC Settlement Agreement with the Office of the Utilities Consumer Advocate - Enforcement and Administrative Penalty,* AUC Decision 27705-D01-2022**

AUC Enforcement - Confidentiality Order

Application

AUC Enforcement staff applied to the AUC for approval of a settlement agreement reached between the Office of the Utilities Consumer Advocate ("UCA") and the AUC Enforcement staff. In the settlement agreement, the UCA admitted to a contravention and agreed to the imposition of an administrative penalty of $2,500 under sections 63(1)(a) and 63(2)(a) of the *Alberta Utilities Commission Act*. The settlement agreement was reached in response to the UCA disclosing confidential information on the public record of Proceeding 26615-D01-2022.

Decision

The AUC approved the settlement agreement. Following the settlement agreement, the AUC imposed a one-time penalty on the UCA of $2,500 for the contravention of an AUC confidentiality order.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37.2 - ss 8, 23(1) and 63.

AUC Rule 001: *Rules of Practice* - s 30.11.

AUC Rule 013: *Criteria Relating to the Imposition of Administrative Penalties*.

***ENMAX Energy Corporation 2023 Non-Energy Regulated Rate Option Interim Tariff,* AUC Decision 27714-D01-2022**
Electricity - Rates

Application

ENMAX Energy Corporation ("EEC") requested approval of 2023 administration charges on an interim refundable basis, to be implemented effective January 1, 2023, as part of its 2022-2024 non-energy regulated rate option ("RRO") Non-Energy tariff application.

Decision

The AUC approved the 2023 interim administration charges proposed by EEC on an interim refundable basis in part.

Applicable Legislation

Regulated Rate Option Regulation, AR 62/2005.

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

Pertinent Issues

The AUC found that continuing the existing administration charges is likely to give rise to a revenue deficiency. The AUC was, however, not satisfied by the quantum of the proposed administration charges requested by EEC. EEC applied to recover 60 percent of the difference between the 2022 interim administration charges and its applied-for 2023 administration charges. The AUC was not persuaded that the administration charges requested sufficiently minimize the risk of over-collection.

The AUC allowed EEC to implement interim administration charges on an interim refundable basis of $0.2392 per day for residential customers and $0.2178 per day for commercial customers, effective January 1, 2023. These figures represent 30 percent of the difference between the 2022 interim administration charges and the forecasted 2023 administration charges.

***ENMAX Power Corporation 2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates*, AUC Decision 27651-D01-2022**
Gas - Rates

Application

ENMAX Power Corporation ("EPC") made filings in compliance with Decision 26617-D02-2022 and its resulting 2023 distribution rates. The AUC considered EPS's 2023 rebasing by way of a negotiated settlement agreement ("NSA"). In Decision 26617-D01-20226, the AUC approved the NSA and instructed EPC to submit additional filings required for this proceeding.

Decision

The AUC determined that EPC complied with Decision 26617-D02-2022 and approved the resulting 2023 forecast revenue requirement.

The AUC approved, effective January 1, 2023, on an interim basis, EPC's 2023 distribution rates, options and riders, and corresponding rate schedules.

The AUC also approved EPC's 2021 annual transmission access charge deferral account ("TACDA") true-up amount, the distribution tariff terms and conditions, and the finalization of interim 2021 performance-based regulation ("PBR") rates based on the calculation of its 2021 going-in revenue and K-bar amounts.

The AUC directed EPC to apply the 2023 Cost-of-Service ("COS") inflation escalator of 2.68 percent to calculate its 2023 fees and to submit the revised fee schedule as a post-disposition document in the present proceeding by December 19, 2022.

Applicable Legislation

AUC Rule 023: *Rules on Costs in Utility Rate Proceedings*.

Pertinent Issues

In Decision 26617-D02-2022, the AUC directed EPC to revise the applied-for 2023 revenue requirement to reflect the AUC's approval of the NSA. As part of the NSA, EPC agreed to a global reduction to the operation and maintenance ("O&M") forecast and a reduction to capital adjustments. The NSA also includes increases for inflation of $1.41 million and cost of debt of $2.3 million, which reflected the most recent information available. Distribution access service ("DAS") rates are based on a distribution revenue requirement of $293.46 million in 2023 as a result of the NSA.

Decision 26617-D02-2022 required EPC to include, in its compliance filing, the calculation of 2023 rates based on the approved revenue requirement. EPC was directed to include the following information that typically accompanies the calculation of rates in the compliance filings:

- 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.
- 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.
- Terms and conditions of service for 2023 for approval.
- A true-up of the prior approved deferral accounts, such as the amounts included in the Y factor and 2021 TACDA true-up.
- All currently approved deferral accounts and rate riders shall continue to be applied in 2023. The differences between forecast and actual costs for amounts in these accounts will be subsequently trued up in the annual PBR rate adjustment filings.
- Any other items required to support the proposed 2023 distribution tariff.

The AUC approved the resulting 2023 forecast revenue requirement of $291.75 million and determined that EPC has complied with Decision 26617-D02-2022.

***EPCOR Distribution & Transmission Inc. 2023 Cost-of-Service Compliance Filing and 2023 Distribution Rates,* AUC Decision 27653-D01-2022**
Electricity - Rates

Application

EPCOR Distribution & Transmission Inc. ("EDTI") made filings in compliance with Decision 26617-D02-2022 and its resulting 2023 distribution rates. The AUC considered 2023 rebasing by way of a negotiated settlement agreement ("NSA"). In Decision 26617-D01-2022, the AUC approved the NSA and instructed EDTI to submit additional filings required for this proceeding.

Decision

The AUC determined that EDTI complied with Decision 26617-D02-2022 and approved the resulting 2023 forecast revenue requirement. The AUC also approved EDTI's 2021 annual transmission access charge deferral account ("TACDA") true-up amount and the 2023 system access service ("SAS") transmission rates. Finally, the AUC approved the 2023 distribution rates, riders and corresponding rate schedules, subject to EDTI filing post-disposition documents reflecting adjustments to the Residential Customer class consumption forecast.

Applicable Legislation

AUC Rule 021: *Settlement System Code Rules*.

AUC Rule 023: *Rules on Costs in Utility Rate Proceedings*.

Pertinent Issues

In Decision 26617-D01-2022, the AUC accepted the NSA reached between EDTI and the Office of the Utilities Consumer Advocate (UCA) as reasonable. Subsequently, in Decision 26617-D02-2022, the AUC directed EPCOR to file a compliance filing to the decision, including all information that typically accompanies the calculation of rates, including the following:

- A 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.
- A 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.
- Terms and conditions of service for 2023 for approval.
- A true-up of the prior approved deferral accounts, such as the amounts included in the Y factor and 2021 Transmission Access Charge Deferral Account true-up.
- All currently approved deferral accounts and rate riders shall continue to be applied in 2023. The differences between forecast and actual costs for amounts in these accounts will subsequently be trued up in the annual PBR rate adjustment filings.
- Any other items required to support the proposed 2023 distribution tariff.

The AUC approved EDTI's 2023 distribution rates, including the options and riders, on an interim basis, effective January 1, 2023, subject to EDTI filing an updated set of schedules by December 19, 2022. These rates will remain interim pending the finalization of all outstanding placeholders.

***EPCOR Energy Alberta GP Inc. 2023 Interim Regulated Rate Tariff Application,* AUC Decision 27773-D01-2022**

Electricity - Rates

Application

EPCOR Energy Alberta GP Inc. ("EEA") applied for approval of interim 2023 rates applicable to the non-energy regulated rates tariff ("RRT").

Decision

The AUC approved EEA's 2023 interim RRT non-energy rates, effective as of January 1, 2023.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 - s 122.

AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

Pertinent Issues

EEA indicated that it intends to file its 2023-2025 non-energy RRT application before the end of 2022. The AUC noted that the 2023-2025 application would not be decided before the beginning of 2023; as a result, the AUC determined for EEA to continue the approved 2022 non-energy rates on an interim refundable basis.

FortisAlberta Inc. 2023 Cost-of-Service Compliance Filing and 2023 Rates, **AUC Decision 27671-D01-2022**
Gas - Rates

Application

The AUC approved FortisAlberta Inc.'s ("FortisAB") 2023 rebasing in Decision 26615-D01-2022. In addition to reviewing the 2023 forecast revenue requirement, that decision also included consideration of the efficiencies achieved by the distribution facility owner ("DFO") and the sharing of those efficiency gains with customers, as well as an assessment of the prudence of actual costs incurred to date by the DFO during the PBR2 term.

In Decision 26615-D01-2022, the AUC directed several changes to the applied-for revenue requirement by FortisAB. In the present application, FortisAB has filed information to support its compliance with those AUC directions.

Decision

The AUC determined that FortisAB complied with the directions issued in Decision 26615-D01-2022, except for the directed adjustments to inflation escalators. The AUC approved FortisAB's 2023 distribution rates, options and riders, and corresponding rate schedules on an interim basis and the 2023 system access service ("SAS") rates. The AUC also approved the 2021 annual transmission access charge deferral account ("TACDA") true-up amount and the retailer terms and conditions of electric distribution service. The AUC approved the finalization of FortisAB's interim 2021 performance-based regulation ("PBR") rates.

Applicable Legislation

Electric Utilities Act, SA 2003, c E-5.1 - ss.13 and 122.

AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*.

AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.

AUC Rule 023: *Rules on Costs in Utility Rate Proceedings*.

Pertinent Issues

In addition to responding to the AUC's directions, FortisAB was also required to include, in its compliance filing, the calculation of 2023 rates based on the approved revenue requirement. FortisAB was directed to include the following information that typically accompanies the calculation of rates in the compliance filings:

- 2023 billing determinant forecast reflective of the last approved Phase 2 methodologies and most recent data.

- 2023 distribution tariff based on the approved revenue requirement and the associated bill impact analysis.

- Terms and conditions of service for 2023 for approval.

- True-up of the prior approved deferral accounts, such as the amounts included in the Y factor and 2021 TACDA true-up.

- Currently approved deferral accounts and rate riders, which shall continue to be applied in 2023. The differences between forecast and actual costs for amounts in these accounts will subsequently be trued up in future annual PBR rate adjustment filings.

- Any other items required to support the proposed 2023 distribution tariff.

The AUC approved FortisAB's 2023 rates, options, riders and corresponding rate schedules on an interim basis, effective January 1, 2023. These rates will remain interim pending the finalization of all outstanding placeholders. The AUC directed FortisAB to use a single inflation escalator of 2.68 percent for both capital and O&M forecasting and to include this update to its forecasts as part of the 2022 actual closing rate base true-up. Finally, the AUC approved FortisAB's retailer terms and conditions of electric distribution service as filed on a final basis, effective January 1, 2023.

***FortisAlberta Inc. Application to Amend the Terms and Conditions of Electric Distribution Service Pursuant to Decision 27202-D01-2022,* AUC Decision 27560-D01-2022**
Terms and Conditions - Transfer of Service

Application

FortisAlberta Inc. ("FortisAB") applied for approval of changes to its terms and conditions of electrical distribution service ("T&Cs"). FortisAB proposed the changes in response to directions issued by the AUC in Decision 27202-D01-2022, the decision regarding FortisAB's compliance filing to 26668-D01-2021. FortisAB proposed the same changes to the T&Cs as it did in the first compliance filing to address better the instances where a FortisAB customer requests to transfer its service from FortisAB's electric distribution system to a rural electrification association ("REA"). FortisAB clarified its method to address instances in which its customer requests to transfer electricity services from FortisAB's electric distribution system to that of an REA.

Decision

The AUC approved the changes proposed by FortisAB.

Relevant Legislation

Electric Utilities Act, SA 2003, c E-5.1 - s. 127.

Guarantees Acknowledgment Act, RSA 2000, c G-11.

Pertinent Issues

In Decision 26668-D01-2021, the AUC determined that an REA payment to FortisAB must be included under s. 7.5(c) of FortisAB's T&Cs to reduce the exit charges payable by the transferring customer. In Decision 27202-D01-2022, the AUC approved changes to the wording of s. 7.5 proposed by FortisAB. However, the AUC determined that the proposed method to calculate the exit charge and effect the transfer of a customer's transfer from FortisAB to an REA lacked clarity and completeness and was not compliant with the AUC's directions in Decision 26668-D01-2021.

To clarify the language and method to carry out the permanent disconnection, FortisAB restated and elaborated on the steps it would take to carry out a permanent disconnection arising from the transfer of a customer and the associated facilities to an REA.

EQUS REA LTD. ("EQUS") raised several concerns with the proposed language at the end of s. 7.5 of the T&Cs and the proposed method to implement that change. Specifically, EQUS: (i) objected to FortisAB's proposal to withhold the transfer of facilities pending both REA and final customer payments; (ii) argued that the *Guarantees Acknowledgment Act* would be triggered by FortisAB's proposed contract termination proposal; and (iii) asserted that FortisAB's method to implement its changes to the end of s. 7.5 would amount to unlawful security.

Submissions from EQUS did not convince the AUC that the language promoted a discriminatory treatment of customers, nor did it increase the regulatory burden and ambiguity. The AUC was satisfied that, as long as the proposed method to effect the transfer of the customer to an REA is adhered to, the *Guarantees Acknowledgment Act* issues should not arise. The AUC also saw no merit in the argument that FortisAB withholding the asset transfer until a residual exit charge payment is made is essentially a form of security.

***NU-E Corp. Lethbridge 1 Solar Project Checklist Application,* AUC Decision 27721-D01-2022**
Solar Power - Facilities

Application

NU-E Corp ("NU-E") filed a checklist application with the AUC to construct and operate the 8.75-megawatt ("MW") Lethbridge 1 Solar Project (the "Power Plant") on 40 acres of private, cultivated land in the city of Lethbridge. NU-E applied to connect the Power Plant to the City of Lethbridge Electric Utility's distribution system.

Decision

The AUC approved the applications to construct, operate and connect the Power Plant.

Relevant 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.

AUC Rule 012: *Noise Control*.

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

Rocktree Solar Inc. Rocktree Solar Project, AUC Decision 27445-D01-2022
Solar Power - Facilities

Application

Rocktree Solar Inc. ("Rocktree"), wholly owned and operated by Volatrix Group Inc., applied for permission to construct and operate the 18.4-megawatt ("MW") Rocktree Solar Project (the "Project"). The Project will be constructed on 110 acres of private, cultivated land two kilometres south of Spruce Grove in Parkland County. The Project will be connected to the distribution system of FortisAlberta Inc.

Decision

The AUC determined that approval of the Project is in the public interest and therefore approved the applications from Rocktree, subject to conditions related to a conservation and reclamation plan for the Project, post-construction monitoring, noise control, solar glare and final equipment selection.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37 - s. 17.

Hydro and Electric Energy Act, RSA 2000, c H-16 - ss. 11 and 18.

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 Environment and Protected Areas - Fish and Wildlife Stewardship: *Conservation and Reclamation Directive for Renewable Energy Operations*.

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

***Solar Krafte Utilities Inc. Vauxhall Solar Farm,* AUC Decision 27077-D01-2022**
Solar Power - Facilities

Application

Solar Krafte Utilities Inc. ("Solar Krafte") applied for approvals to construct and operate a 60-megawatt ("MW") Vauxhall Solar Power Plant and associated Solstice 549S Substation (collectively, the "Project"). The Project will be constructed on 194 hectares of privately owned land three kilometres northwest of the town of Vauxhall.

Decision

The AUC approved the application from Solar Krafte to construct and operate the Vauxhall Solar Power Plant and associated Substation.

Applicable Legislation

Alberta Utilities Commission Act, SA 2007, c A-37. - s 17.

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

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

Conservation and Reclamation Regulation, Alta Reg 115/1993 - s. 17.

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

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

AUC Rule 012: *Noise Control*.

Pertinent Issues

In the original application, Solar Krafte proposed a project with a capability of 150 MW.. Before submitting its application, Solar Krafte reduced the size of the Project to 60 MW. In July 2022, after the application was submitted to the AUC, Solar Krafte removed 230 acres of the project area.

Environment, Noise and Glare

The Project, as originally submitted to the AUC, posed a moderate risk to wildlife and wildlife habitat, a high risk to birds, and a moderate risk to wetlands and potentially sensitive amphibian breeding sites. Since an overall reduction in impacts to the surface was proposed by Solar Krafte's amendments, including the avoidance of all native grassland and removal of infringements to several setbacks, the AUC determined that an updated referral report was not required.

The permanent infrastructure of the final Project would impact five wetland setbacks. The AUC was satisfied by the mitigation measures committed to by Solar Krafte. Considering the updated project layout and implementation of mitigation measures, the AUC accepted that the overall residual effects of the Project would not be significant.

The updated application indicated that the final Project would comply with Rule 012: *Noise Control* and regulations regarding solar glare. To ensure continued compliance with applicable rules, the AUC made the approval conditional on requirements regarding solar glare mitigation and reporting and sound level surveillance and reporting.

Reclamation and Municipally Enacted Laws

The Municipal District ("MD") of Taber submitted that the application should be denied because of a lack of reclamation security. Alternatively, the MD of Taber requested that Solar Krafte be required to post reclamation security in an amount not exceeding $10,000,000.00 as a condition of approval to be held in trust for the hosting landowners. The MD of Taber argued that: (1) the issuance of such security was required by the public interest, and (2) the MD of Taber's Land Use Bylaw (the "Bylaw") required Solar Krafte to issue security in respect of its reclamation obligations.

The AUC determined that Solar Krafte was not required to issue security in respect of its reclamation obligations because the Project is in the public interest without the condition requested by the MD of Taber. The AUC also found that security was not required because, according to the Bylaw and the exercise of the Development Authority's discretion under the Bylaw, no municipal laws require security to be provided.

The MD of Taber argued that reclamation security should be required to ensure the Project is in the public interest. Their concern was that if Solar Krafte became insolvent and could not fund the discharge of its regulatory reclamation obligations, the security would ensure that the liabilities were paid for. Further, the MD of Taber argued that the Supreme Court of Canada had endorsed the polluter pay principle.

Solar Krafte filed a conservation and reclamation plan in its application and argued that because solar projects require a high initial capital investment and have stable revenues and lower ongoing operating expenditures, any financial issues it encounters will result in a dispute as to who is entitled to continue operating the Project. It would not likely result in the abandonment of the Project. The AUC was satisfied that the filings meet the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, Hydro Developments and Gas Utility Pipelines*.

The AUC rejected the argument from the MD of Taber that the polluter pay principle requires the AUC to impose a reclamation security condition. This broad principle has been recognized as a tenet of Canadian environmental law and is recognized by the Environmental *Protection and Enhancement Ac*t, but does not dictate the use of specific regulatory tools, such as reclamation security, when an existing regulatory scheme is already in place concerning reclamation obligations. The AUC determined that compliance with existing reclamation requirements, in the form of *the Environmental Protection and Enhancement Act*, the *Conservation and Reclamation Regulation* and the

Conservation and Reclamation Directive for Renewable Energy Operations, was sufficient to address reclamation concerns.

The AUC determined that according to the Bylaw, the MD of Taber delegated the discretion to impose conditions on development permits to its Development Authority. Even if this discretion included the ability to impose security obligations on Solar Krafte in respect of the Project – and it is not clear that it does – in this case, the Development Authority has not done so.