ENERGY REGULATORY REPORT

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

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

IN THIS ISSUE:

SUPREME COURT OF CANADA

***Reference re Greenhouse Gas Pollution Pricing Act,* 2021 SCC 11**
Greenhouse Gas Emissions - Peace Order and Good Government

In this decision, the SCC majority determined that the *Greenhouse Gas Pollution Pricing Act* ("*GGPPA*")*,* passed by Parliament in 2018, is constitutional.

Part 1 of the *GGPPA* establishes a fuel charge that applies to producers, distributors, and importers of various types of carbon-based fuel. Part 2 sets out a pricing mechanism for industrial greenhouse gas ("GHG") emissions by large emissions-intensive industrial facilities.

Saskatchewan, Ontario, and Alberta challenged the constitutionality of the *GGPPA* on grounds related to federalism. Ontario further argued that the levies imposed by the *GGPPA* are unconstitutional*.* Unlike the courts of appeal for Saskatchewan and Ontario, the Court of Appeal of Alberta held that the *GGPPA* is unconstitutional. The Attorney General of British Columbia, who had intervened in the Court of Appeal of Alberta, the Attorney General of Saskatchewan, and the Attorney General of Ontario appealed as of right to the Court. The reference question before the SCC remained whether the *GGPPA* is, in whole or in part, unconstitutional.

<u>Analysis - Classification of the GGPPA</u>

In a 6-3 majority decision, the majority found the *GGPPA* to be constitutional. They noted that global warming causes harm beyond provincial boundaries and that it is a matter of national concern under the "*peace, order and good government*" clause of the Constitution and was therefore under federal jurisdiction.

National Concern Test

The Court noted that determining whether an issue is of national concern involves a three-step analysis. The matter must be sufficiently important to the country as a whole to deserve and require consideration as a possible matter of concern. Second, the matter must have a singleness, distinctiveness, and indivisibility. Third, it must be shown that the proposed matter has a scale of impact on provincial jurisdiction that is reconcilable with the division of powers.

With regard to the first step, the SCC noted that the issue was not the regulation of GHG emissions generally, but determining whether the establishment of minimum national standards of GHG price stringency to reduce GHG emissions is a matter of national concern.

All parties agreed that climate change is an existential challenge. They agreed that it poses a threat of the highest order to the country and to the world. The SCC majority found that this, as well as the history of efforts to address climate change in Canada and the fact that broad consensus exists among international expert bodies such as the World Bank and the Organization for Economic Cooperation and Development, that carbon pricing is a critical measure for the reduction of GHG emissions, shows that carbon pricing is integral to reducing GHG emissions and, more importantly, that establishing a minimum national standard of GHG price stringency to reduce GHG emissions is of concern to Canada as a whole.

With regard to the second part of the test, the SCC must also ensure that the principles of federalism are upheld. To prevent federal overreach, jurisdiction based on the national concern doctrine should be found to exist only over a specific and identifiable matter that is qualitatively different from matters of provincial concern. The second principle to be considered at this stage of the inquiry is that federal jurisdiction should be found to exist only where the evidence establishes the provincial inability to deal with the matter.

The SCC emphasized that these gases are a specific and precisely identifiable type of pollutant. It further found that GHG emissions are predominantly extra-provincial and international in their character and implications. It found that the type of pollutant covered by the matter at issue is identifiable and qualitatively different from matters of provincial concern and that the regulatory mechanism of GHG pricing is a specific and limited one. GHG pricing does not amount to the regulation of GHG emissions generally.

The SCC majority noted the inability of the provinces to establish a binding outcome-based minimum legal standard — a national GHG pricing floor — that applies in all provinces and territories at all times. While the provinces could cooperatively establish a uniform pricing scheme, any province could choose to withdraw at any time. While a cooperative scheme could continue to exist if one province was not included or withdrew, this would threaten the scheme's success. The SCC emphasized that the issue was the success, not merely the existence of such a scheme.

The SCC noted that the principles underpinning the singleness, distinctiveness, and indivisibility inquiry clearly support a finding that the federal government has jurisdiction over the matter of establishing minimum national standards of GHG price stringency to reduce GHG emissions.

The third part of the test requires an analysis to determine whether the proposed matter of national concern is reconcilable with the division of powers. The SCC majority found that the impact of the *GGPPA* on the jurisdiction of the provinces was limited. While there is an impact on provinces' freedom to legislate, this impact was determined to be narrow, specific, and limited to the pricing of GHG emissions. The federal government established a nationwide price on carbon pollution but left the provinces with the power and freedom to regulate GHG emissions. Canada would not interfere as long as the provinces meet the federal government's outcome-based targets.

The SCC majority accordingly found that the federal government did not exceed its jurisdiction with the *GGPPA*. The *GGPPA* is not unconstitutional on the grounds of federalism.

Validity of the Levies as Regulatory Charges

Ontario argued that fuel and excess emission charges imposed by the *GGPPA* are not sufficiently tied to the regulatory scheme to be considered constitutionally valid regulatory charges. While the regulatory quality of the scheme created by the *GGPPA* was not an issue, Ontario was concerned with the connection between the levy and the regulatory scheme, as the *GGPPA* does not require that the revenues collected under Parts 1 and 2 are expended in a way connected to the regulatory purpose of the *GGPPA*.

The SCC majority found that regulatory charges need not reflect the cost of the scheme. The amount of a regulatory charge whose purpose is to alter behavior is set at a level designed to proscribe, prohibit, or lend preference to a behavior. It determined that the required connection with the scheme will exist where the charges themselves have a regulatory purpose. Where, as in the instant case, the charge itself is a regulatory mechanism that promotes compliance with the scheme or furthers its objective, the nexus between the scheme and the levy inheres in the charge itself.

The SCC majority found that the levies are constitutionally valid regulatory charges.

COURT OF QUEEN'S BENCH OF ALBERTA

Hart v ATCO Electric Ltd, 2021 ABQB 162

Surface Rights Board; Appeal; Compensation Payable

In this matter, the Court granted an appeal a decision of the Alberta Surface Rights Board ("SRB") in relation to the compensation payable to the Appellant arising from the presence of two steel tower structures on the Appellant's lands.

Background

This appeal required the Court to consider the decision of the SRB that determined the surface rights annual compensation payable to the Appellant arising from the presence of two steel tower structures on the Appellant's lands.

The Court noted that the assessment must be conducted in accordance with the *Surface Rights Act*, RSA 2000 c S-24 ("the *Act*"). The assessment will, at least in part, involve a consideration of whether the Appellant's lands are "improved pasture" lands; whether, on the totality of the evidence, compensation payable in relation to "improved pasture" lands should be the same as, or different from, the surface rights annual compensation payable for "native prairie" lands, and whether, on the totality of the evidence, "improved pasture" lands are the same as, or different from "Cultivated Lands."

The Right of Way Agreement ("ROW Agreement") required that ATCO Electric pay annual compensation in the amount of

(a) $1,380.00 for each structure to be placed on "Cultivated Lands,"

(b) $552.00 for each structure to be placed on "Uncultivated Lands"; and

(c) $690.00 for each structure to be placed on "Head Lands."

ATCO Electric Ltd. ("AE") proposed that it pay a total of $1,104 ($552 per tower) for the next five years, an amount that was upheld by the SRB.

Standard of Review

In Alberta, the question of how much compensation should be payable by an operator to an owner is "in essence a question of fact or, if valuation principles such as a pattern of dealing and adverse effect can be said to be legal principles, one of mixed fact and law". As a result, the SRB Decision in relation to the amount of the compensation payable should be reviewed on a standard of palpable and overriding error. Questions involving interpretation of the Act are reviewed on a standard of correctness.

Issues to be Decided

Scope and Nature of this Appeal

The function of the SRB on a compensation review hearing under s 27 is not to determine what compensation should properly have been paid in the past but to determine the appropriate compensation going forward.

Has the Appellant Proven That the Lands Are "Improved Pasture"?

The SRB found that one of the two towers was located on "improved pasture", and the other was located on "native prairie". The Court held that the SRB made a palpable and overriding error in reaching this conclusion and found that both towers are located on "improved pasture" based on evidence from the Appellant.

Is it Appropriate to take into Consideration the Terms of the ROW Agreement?

No evidence was tendered to the SRB or during the *de novo* appeal hearing to explain how AE derived the amount of compensation previously paid to the Appellant. Nor did AE offer any explanation in any of their submissions. Instead, AE had consistently taken the position that this is simply irrelevant.

The Court concluded that this issue is not irrelevant and that the proper amount of the compensation payable under the terms of the ROW Agreement is a relevant factor to be considered in an s 27 analysis. The Court, therefore, found that when the SRB failed to do so, they made a palpable and overriding error.

The Court concluded that the terms of the ROW Agreement are fundamental to the relationship between the parties, and it is a palpable and overriding error to fail to consider the ROW Agreement as the foundation for the rate of compensation review under s 27.

The SRB, when determining compensation, must not consider the factors in s 25(1)(c) and (d) of the *Act* in isolation (these subsections address the fact that in determining compensation, the SRB may consider the loss of use and adverse effect). Instead, the SRB must also consider the scheme of the *Act* and the relevant context, which, in this case, includes the agreements between the parties, specifically the ROW Agreement. It is only when the scheme of the *Act* and the relevant context is considered that the factors in s 25(1)(c) and (d) can be properly assessed.

The legislative scheme places great importance on the integrity of negotiations between the parties and the agreements that are made relating to compensation. This suggests that the intention of the Legislature was to preserve agreements between the parties and to make any alterations to the agreements minimally invasive.

When interpreting and applying the evidence to the factors in s 25(1)(c) and (d) and the pattern of dealings ("PoD") analysis, the SRB had jurisdiction to increase or decrease the rate of compensation for "Cultivated Lands," "Head Lands" and "Uncultivated Lands" but it did not have the jurisdiction to amend any other provision or term of the ROW Agreement. It did not have the power to alter the structure of the three categories of use that the parties had agreed to. It did not have jurisdiction to amend the definition of "Cultivated Land" in the ROW Agreement so as to remove "improved pasture" from the definition and to insert it into the definition of "Uncultivated Lands." This was contrary to the intention and reasonable expectations of the parties.

Thus, as between themselves, the parties had specifically agreed that there was a difference between "improved pasture" and "native prairie." The SRB made a palpable and overriding error when it found no distinction between "improved pasture" and "native prairie" for the purpose of the s 27 compensation review process.

Does the PoD Evidence Support the SRB Decision?

Determining the amount of compensation payable to an owner of land in accordance with s 27 of the Act is a forward-looking exercise that is designed to identify the amount of the annual compensation that is appropriate in all of the circumstances.

While s 25(1)(c) and (d) identify the factors to be considered, no specific procedure is mandated by the Act for determining the amount of compensation payable. However, at least since 1978, evidence of a PoD has been the preferred approach when conducting the analysis. The PoD serves as a surrogate for the s 25(1)(c) and (d) factors and arises "where there are such a number of deals established so that it may be said that a pattern has been established by negotiations between the landowners and oil companies in a district". The principle contemplates "comparable" patterns of dealing in terms of the rights granted, the type of land, proximity, date, acreage, and the nature of the parties.

The SRB correctly observed that the practice of the SRB is to base compensation on a PoD unless there are cogent reasons for doing otherwise. The SRB then went on to consider the evidence of the PoD before reaching its conclusion on compensation. The Court found that the evidence did not support the SRB Decision, and in coming to its decision, the SRB's reasoning process and outcome were infected with palpable and overriding error.

Has the Appellant Met the Onus to Prove a Rate of Compensation Different Than That Determined by the SRB?

After considering the totality of the evidence, the Court was satisfied that the Appellant met the onus to prove a rate of compensation different than that determined by the SRB. The Court concluded that a proper PoD had been established for "Cultivated lands" within the meaning of the ROW Agreement. Since the Appellant's lands are "improved pasture" and thus "Cultivated lands," the PoD suggests that the rate of compensation payable to the Appellant should be $1,380.00 per tower.

Having determined that a proper PoD has been established, it was still necessary to consider whether there is any cogent reason to depart from the use of the PoD. The s 27 compensation review process is intended to make the landowner whole. The compensation should not enrich the landowner and should not give rise to a windfall.

AE agreed to include "improved pasture" in the definition of "Cultivated Lands" and thus agreed that "improved pasture" lands would be paid at the same rate as other types of cultivated lands. There were good reasons to have a broad definition of "Cultivated Lands". There is no unfairness associated with this. AE cannot ignore the terms of its own agreement.

The compensation process is not scientific and cannot readily identify with any precision the actual adverse impact or loss of use that a landowner incurs because of the presence of the towers on the lands. Many of the impacts are subjective and intangible.

If the ROW Agreement is ignored, it is arguable that the AE towers have a greater adverse effect on lands planted with cereal crops than "improved pasture" lands. The ROW agreements contain a very broad definition of "Cultivated Lands". This necessarily means that some owners will receive more attractive compensation than others. But that is what the parties agreed to.

There is thus no reason to deviate from the PoD in this case.

<u>Conclusion</u>

The SRB Decision was based on palpable and overriding error. The Court, therefore, directed that the SRB compensation order be varied to reflect the compensation payable to the Appellant in the amount of $1,380.00 for each of the two towers.

ALBERTA ENERGY REGULATOR

Vantage Point Resources Inc. Regulatory Appeal of a Reclamation Certificate, AER Decision 2021 ABAER 004
Reclamation Criteria - Seeded Species

In this decision, the Alberta Energy Regulator ("AER") revoked the decision of the AER Enterprise Reclamation Group ("ERG") to issue a reclamation certificate to Vantage Point Resources Inc. ("Vantage").

Introduction

Vantage, as lessee and operator, applied for a reclamation certificate for a well site and access road about 30 kilometers east of Oyen and about 140 km north of Medicine Hat. The owner of the site filed a statement of concern ("SOC") in respect of Vantage's application.

In response to the SOC, an ERG reclamation assessor visited the site, completed an assessment of the site, and recorded her assessment in a reclamation certificate program criteria report. Based on the results of the detailed site assessment ("DSA") submitted by Vantage and her own assessment, the ERG assessor recommended the AER issue the reclamation certificate. The AER decision maker, by way of reasons, disposed of the owner's SOC without a hearing and issued the reclamation certificate.

The owner of the site requested a regulatory appeal, which the AER granted.

History of the Site

One well was drilled on the site in 1992 and abandoned in 1994. Multiple operators held the lease for the site over the years. The site was first reclaimed in the early 2000s, with seeding taking place about that time. In preparation for filing an application for a reclamation certificate, the operator at the time found a portion of the site to be contaminated. Subsequently, the contaminated portion of the site was remediated and then reclaimed a second time, with reseeding in 2013.

Vantage acquired the site in 2018. It did not conduct reclamation or remediation work on the site. The remediation work is not an issue in this regulatory appeal. After it became the lessee and operator of the site, Vantage had the DSA carried out by a consultant. The DSA was completed and submitted as part of a routine reclamation certificate application. The lease perimeter fence was removed at or near the time of the reclamation certificate application, except for six fence posts that remain in the northernmost low-lying area.

The owner of the site was concerned that the site was seeded with a forage/hay seed mix and not with Altai wild rye, even though he told both the operator who conducted the reclamation work before the remediation in 2013, and the operator who conducted the post-remediation reclamation work, that he wanted the site seeded with Altai.

Regulatory Framework

The duty to conserve and reclaim land, and obtain a reclamation certificate, arises from Section 137 of the Environmental Protection and Enhancement Act ("*EPEA*"). "Reclamation," as defined in *EPEA*, includes the procedures, operations, or requirements specified in the regulations. Under Section 2 of *EPEA*'s Conservation and Reclamation Regulation ("*CRR*"), the objective of conservation and reclamation is to ensure the reclaimed land has an equivalent land capability.

The *CRR* also requires operators to reclaim specified land in accordance with applicable standards, criteria, and guidelines. Specified land is land that is being or has been used or held for, or in connection with, certain activities that include the construction, operation, or reclamation of a well.

The applicable criteria are found in the 2010 *Reclamation Criteria for Wellsites and Associated Facilities for Cultivated Lands* ("reclamation criteria") and are applied "to evaluate whether a site has met equivalent land capability." The reclamation criteria specify that an operator must include in its application an evaluation of whether the lease site meets the reclamation criteria by comparing the reclaimed area to adjacent lands in terms of vegetation, soil, and landscape.

In addition, Section 12(1)(a) of the *CRR* states that an application for a reclamation certificate is to contain the same information as is required in the well site reclamation application form. This information includes a DSA that provides comparisons of on- and off-site landscape, vegetation, and soil parameters using the reclamation criteria and documents whether, in the opinion of the assessor, a site meets equivalent land capability. Consistent with the *CRR* definition of equivalent land capability, the reclamation criteria do not require lease sites to be returned to the exact state they were in before the activity occurred. According to Section 6.1 of the reclamation criteria, an equivalent land capability is "based on land function and operability that will support the production of goods and services consistent in quality and quantity with the surrounding lands."

Specified Enactment Direction 002: Application Submission Requirements and Guidance for Reclamation Certificates for Well Sites and Associated Facilities ("*SED 002*") sets out specific requirements for the information to be included in an application for a reclamation certificate.

<u>Issues</u>

As noted, the reclamation criteria require evaluation of landscape, soil, and vegetation parameters on the reclaimed site and consultation with the current landowner or occupant.

Does the Site Meet the Applicable Reclamation Criteria?

(a) Compatibility of Seeded Species Used on the Reclaimed Site with the Adjacent, Off-Site Species

To meet the equivalent land capability standard, the vegetation established on the site must be comparable to off-site vegetation as evaluated using the DSA. The on-site crop must be "compatible" with the off-site, or, if it is not, it must have been approved by the landowner or must be able to be managed the same as the off-site crop.

In this case, the on-site crop was not approved by the owner of the site. The AER, therefore, had to decide what "compatible" means in these circumstances.

The owner of the site estimated the Altai concentration on the site to be significantly lower than the concentration in the Altai field. However, both the DSA and the ERG assessor concluded the concentrations were comparable. The DSA estimate was based on a close assessment of sample locations on and off the site. In addition, the photos included with the DSA and reviewed with the owner of the site at the hearing show a noticeable percentage of Altai on site, although the photos do not allow for an estimate or comparison of the relative concentrations. The AER found the DSA assessment persuasive and conclude that, while the vegetation on the site was not the same as the vegetation on the adjacent lands, it was comparable.

The AER found that the Altai field has not been used for Altai seed crop and is not being managed for that purpose. As a result, the AER was persuaded that the healthy perennial forage established on the site is compatible with the adjacent off-site species.

(b) Incorporation of Vegetation Established on the Reclaimed Site in the Operation and Management of Adjacent Lands

To meet the equivalent land capability standard, vegetation established on a reclaimed site must be able to be incorporated into the operation and management of adjacent lands. The reclamation criteria do not include a definition of operability in the vegetation criteria. In the AER's view, the criteria suggest that factors such as differences in crop measurement and crop health and the presence of weeds can negatively affect the incorporation of a reclaimed site into the operation and management of the adjoining lands.

The AER found that it had no reason to question the DSA's conclusion that crop measurement and health and presence of weeds on the site were comparable to the adjacent lands.

Altai has been seeding naturally onto the site. Likewise, the evidence of crested wheatgrass and other grasses off-site confirms the off-site vegetation includes species other than Altai. The owner considered that unacceptable in what he described as a seed crop. If the Altai field was being actively managed as a seed crop, the presence of other forage species might cause the owner to manage the site differently than the Altai field. However, the AER found that the Altai field is not being actively managed, so there is no direct and adverse interference with the owner's management of the adjacent land.

Facilities and features such as fence posts can interfere with the incorporation of reclaimed lands into the operation and management of adjacent lands and can also pose safety issues. *SED 002* requires written approval from the landowner if fences are to be left in place. Otherwise, they must be removed and the holes filled before an application for a reclamation certificate is filed. Considering Vantage's admission about the fence posts and in the absence of the owner's written consent to leave fence posts in place on the site, Vantage should have removed the six remaining fence posts before the reclamation certificate application was filed. The presence of the fence posts on the site without the owner's expressed consent prevented the AER from finding that the site can be incorporated into the operation and management of the adjacent lands.

(c) Was There Adequate Landowner Consultation Concerning Seeded Species Used on the Reclaimed Site?

The reclamation criteria and *SED 002* clearly require consultation as a part of the reclamation process leading up to the application for a reclamation certificate. The reclamation criteria do not provide guidance on the sufficiency of consultation but does state in Section 10.1 that vegetation choices should be made along with the land manager, who in this case is the landowner.

The AER found that Vantage did not consult as required by the *SED 002* and the reclamation criteria. This is because, before filing its application for the reclamation certificate, Vantage did not consult directly with the owner, nor did it take steps to ensure that its consultant had engaged appropriately with the owner regarding whether he had any concerns about the site.

Was the Application Technically Complete and Accurate?

SED 002 provides detailed guidance to operators about the requirements for completing an application for a reclamation certificate. The provisions set out above require operators to consult with landowners so that they can learn and address landowner concerns and ensure that plant species used in the reclamation process are "acceptable." Section 6.2.3 of *SED 002* requires that the reclamation application indicate unresolved concerns. Vantage's application did not indicate unresolved concerns but rather suggested that the owner had no concerns.

In the AER's view, the application and supporting materials were incomplete and inaccurate for two reasons. First, they did not reflect the fact that at least six fence posts remained on the site at the time the application was filed. Second, they did not reflect the owner's concern about the use of non-Altai seed on the site. Because of these two shortcomings, the AER also found that the application was potentially misleading.

<u>Conclusion</u>

The AER decided to revoke the decision to issue the reclamation certificate. Vantage was directed to take steps to remove the six remaining fence posts and properly fill the post holes or obtain written consent from the owner to leave them in place before refiling an application for a reclamation certificate for the site. Vantage must also consult with the owner and accurately report any concerns that are unresolved at the time the new application is filed. It was the AER's view that allowing operators to file applications for reclamation certificates that are inaccurate or potentially misleading is not consistent with the safe, orderly, and efficient development of energy resources in Alberta. Inaccurate applications or potentially misleading applications effectively prevent the AER from fully and effectively discharging its mandate.

ALBERTA UTILITIES COMMISSION

***Stakeholder Consultations to Evaluate Performance-Based Regulation In Alberta And To Determine Process To Establish 2023 Rates For Distribution Facility Owners,* AUC Bulletin 2021-04**
Bulletin

Rates for the electric and natural gas distribution facility owners ("DFOs") under the jurisdiction of the AUC are currently regulated under performance-based regulation ("PBR") plans established in Decision 20414-D01-2016 (Errata). At the end of the PBR term, utility revenues and costs are commonly realigned for the benefit of the customers and utilities. To the extent a utility was successful in achieving efficiencies that resulted in cost savings during a PBR plan, relinking of revenues and costs should reflect these realized savings in rates, thereby benefitting customers following the completion of the PBR plan.

Given that less than two years remain in the current performance-based regulation term, the AUC wishes to engage the DFOs and customer groups to structurally assess the approach to distribution rate regulation in Alberta following the expiration of the PBR plans on December 31, 2022. Accordingly, the AUC initiated two streamlined related processes: (i) review and assessment of legacy PBR performance; and (ii) a cost of service review to establish 2023 rates.

<u>Evaluation of PBR in Alberta</u>

The majority of regulated DFOs in Alberta have had rates set under a PBR framework since 2013. Given the near-term completion of the present PBR plans, the AUC saw merit in evaluating the experience acquired with PBR and identifying successes and shortcomings of the first and second PBR plans.

On January 28, 2021, the City of Calgary requested that, as sufficient experience and information are now available to conduct a review, the AUC initiate a review of PBR to assess whether PBR should be continued beyond 2022 and if so, on what terms.

The AUC will gather input and feedback related to the evaluation of PBR in Alberta through its eFiling System under Proceeding 26356. This will be a streamlined, rather than a traditional, proceeding with the primary purpose of facilitating stakeholder input.

<u>Cost of Service Review to Establish 2023 Rates</u>

The AUC found it necessary to, following the end of the active PBR plans in 2022, review the DFOs' costs and revenues to achieve three objectives:

- to identify efficiencies achieved by the DFOs during the 2018-2022 PBR term and pass the benefits on the customers;

- to realign the DFOs' costs and revenues and examine the DFO's forecast costs and rates to ensure they are reflective of the economic situation in Alberta; and

- to assess actual DFO costs in the 2018-2022 PBR term for the purpose of approving the 2023 opening rate base and to ensure forecasts are justified based on the prior-period actuals.

The AUC determined to proceed with a one-year cost of service review based on 2023 forecast costs, including the assessment of prudence of actual costs incurred by the DFOs in the 2018-2022 PBR term. It also decided that the rates approved for 2023 under this cost of service review could be used as going-in rates for subsequent PBR terms after considering the PBR evaluation initiative. This would further enhance regulatory efficiency.

The AUC recognized the potential for significant regulatory burden associated with conducting a cost of service review of the six DFO applications. It is looking to employ alternatives to a traditional review of a utilities' forecast costs. The AUC is looking to adopt a process that requires a year or less of process time and provides certainty to

DFOs and customers through prospective ratemaking. The AUC started Proceeding 26354 to determine streamlined alternatives to the traditional line-by-line review of forecast costs.

***New Performance Standards for Procession Costs and Stage One Review and Variance Applications*, AUC Bulletin 2021-05**
Bulletin

In accordance with its commitment to reduce red tape by eliminating unnecessary applications, procedures, and delays, the AUC has established new internal performance standards and timelines for processing costs and stage one review and variance applications. These apply to all costs and review and variance applications filed on or after March 31, 2021.

Two categories of costs applications and two categories for stage one review and variance applications were established.

Table 1: Performance standards for costs applications

Category	**1 (Routine)**	**2 (Non-routine)**
Description	Single or limited interveners, simple issues	Single or multiple interveners complex issues
Record development	**30 days**	
Metric	80 per cent of costs applications records completed within established timelines	
Decision writing	**20 days***	**50 days***
Metric	100 per cent of decisions issued within established timeframes	
Full cycle	**50 days***	**80 days***

* Unless the application of the record development and decision writing metrics would require the costs decision to be issued prior to the original decision, in which case the decision writing metric will be extended to fall on the fifth day after the original decision is issued.

Table 2: Performance standards for stage one review and variance applications

Category	**1 (Routine)**	**2 (Non-routine)**
Description	Review applications where no submissions are required	Review applications where additional submissions are required
Record development	**30 days**	
Metric	80 per cent of review applications records completed within established timelines	
Decision writing	**20 days***	**50 days***
Metric	100 per cent of decisions issued within established timeframes	
Full cycle	**50 days***	**80 days***

Development of the New Performance Standards

The AUC internally implemented performance standards for costs and review and variance applications in 2020 and has been applying them on a pilot basis to test their efficacy. Draft performance standards were applied to 20 costs applications in the pilot project and resulted in a reduction in the full-cycle processing time of approximately 50 per cent when compared to historical cost order processing times from 2018 and 2019. The AUC will apply the performance standards set out in Table 2 to stage one review and variance applications for the next 12 months and determine, at that time, based on the additional experience, whether further refinements are required.

***Repeal of Rule 030: Compliance with the Code of Conduct Regulation,* AUC Bulletin 2021-06**
Bulletin

On November 5, 2020, amendments to the *Code of Conduct Regulation* were enacted. With these changes, the AUC has repealed Rule 030: Compliance with the Code of Conduct Regulation to streamline compliance reporting and align the timeframe for compliance audits with the amended regulation on a go-forward basis. The repeal of Rule 030 is effective as of April 1, 2021.

Organizations are required to submit their annual compliance report in accordance with Section 33(1) of the *Code of Conduct Regulation*. No further compliance reports outside of those directed to be submitted under the regulation are required to be submitted.

To spread audit engagements over a 10-year rolling cycle, starting in 2022, the AUC has adopted a staggered approach to audit frequency. Audits will be prioritized based on the risk of non-compliance, changes in circumstances, and resource capacity, with the goal to complete all audits by 2028. Each utility will be notified of its scheduled audit at least three months in advance of the engagement. The following ten utilities fall within the audit requirements under the regulation:

- Apex Utilities Inc.;
- ATCO Ltd.;
- Battle River Power Co-op;
- City of Lethbridge;
- City of Red Deer;
- Direct Energy Marketing Limited;
- ENMAX Corporation;
- EPCOR Utilities Inc.;
- EQUS REA Ltd.; and
- FortisAlberta Inc.

***Amendments to AUC Rule 005 will Reduce Regulatory Burden and Improve* Efficiency, AUC Bulletin 2021-07**
Bulletin

The AUC approved amendments to Rule 005: Annual Reporting Requirements of Financial and Operational Results with an effective date of March 31, 2021. The AUC undertook the changes as part of its initiative to improve regulatory efficiency under the *Red Tape Reduction Act,* introduced by the Government of Alberta.

Rule 005 sets out the detailed financial and operational information that is required to be filed annually by utilities, default supply providers, and regulated rate providers.

The proposed changes focused on streamlining the reporting of a utility's annual finances and operations by removing schedules or reporting requirements that the AUC considers may no longer be required or that contain information that is publicly available through other means. The goal was to streamline the reporting of a utility's annual finances and operations while ensuring the provision of a sufficient level of detail.

The AUC reviewed the stakeholder's specific concerns and summarized and addressed the issues raised in the comments in the stakeholder comment tables accompanying the revised rule. This bulletin, the blackline versions related to rule changes, and the tables containing the AUC responses to stakeholder comments are posted in the Rule-related consultations section of the AUC website.

2022 Generic Cost of Capital, AUC Decision 26212-D01-2021
Rates - Return on Equity

In this decision, the AUC set out the return on equity ("ROE") of 8.5 per cent and deemed equity ratio of 37 per cent (39 per cent for Apex Utilities Inc.) collectively referred to as "parameters" for the year 2022 on a final basis. These parameters apply to the following utilities:

- AltaLink Management Ltd. ("AML");
- Apex Utilities Inc. ("AUI");
- ATCO Electric Ltd. ("AE");
- ATCO Gas & Pipelines Ltd. ("AGP");
- ENMAX Power Corporation ("ENMAX");
- EPCOR Distribution & Transmission Inc. ("EDT");
- FortisAlberta Inc. ("Fortis");
- KainaiLink L.P.;
- City of Lethbridge;
- PiikaniLink L.P.;
- The City of Red Deer; and
- TransAlta Corporation.

The parameters set out in this decision do not apply to EPCOR Energy Alberta GP Inc, ENMAX Energy Corporation, and Direct Energy Regulated Services because they are regulated pursuant to the *Electric Utilities Act*, *Regulated Rate Option Regulation*, *Gas Utilities Act*, and the *Default Gas Supply Regulation*, respectively.

Background and Procedural Summary

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

Historically, the AUC considered parameters for each utility on a case-by-case basis. In the 2004 test year, the AUC set a generic ROE for all utilities and adopted an adjustment mechanism formula to determine the ROE in subsequent years. This formula was used from 2005 to 2008, but the global financial recession beginning in 2007 caused the AUC to alter its approach.

Beginning in 2009 as a response to the recession, the AUC began establishing parameters for a two to three-year test period at a time. This is following an intensive regulatory process in a GCOC proceeding in which parties submit a broad range of economic and financial evidence to arrive at expectations of reasonable return.

In January 2020, parties filed evidence for the 2021 GCOC proceeding. On March 19, 2021, the AUC suspended its established process due to uncertainty in financial markets caused by the COVID-19 pandemic. To provide a measure of stability, the AUC utilized a menu-based approach, allowing each utility to select its own preferred option for settings its parameters. This ultimately resulted in the AUC prospectively approving generic parameters for all utilities by extending the approved rate for 2020 to the end of 2021 on a final basis.

The 2022 GCOC proceeding was initiated on December 22, 2020, and sought parties' comments. The first question sought to determine whether there were sufficient grounds to extend the existing parameters for a further period of time or whether they should only be maintained until a specific threshold such as a specific set of market conditions have passed. The utilities predominantly requested that the current parameters be extended for at least one year, dispensing with the need for the 2022 GCOC proceeding, while the Consumers' Coalition of Alberta and the Office of the Utilities Consumer Advocate opposed this view.

Following the comments from parties, the AUC concluded that given the economic and market data that would normally be used to inform its judgment remaining in a state of flux, there is an inadequate basis to depart from the currently approved ROE and equity thicknesses (either up or down).

The AUC also rejected the suggestions made by interveners that a full-scale GCOC proceeding is required citing the probable need for multiple and significant updates regarding economic and market data due to it being a time of major uncertainty. It was also unclear to the AUC that in these circumstances, the rates resulting from a proceeding would be just and reasonable.

Conclusion

In light of the persistence of economic uncertainty caused by the COVID-19 pandemic, the AUC found that there is not sufficient cause to undergo a GCOC proceeding. Therefore, the AUC approved the ROE of 8.5 percent and deemed an equity ratio of 37 percent (39 percent for Apex Utilities Inc.) for the year 2022 on a final basis.

Alberta Electric System Operator Approval of Proposed New Section 502.10 of the ISO Rules and Associated Terms and Definitions, **AUC Decision 26304-D01-2021**

ISO Rules - Revenue Metering System Requirements

In this decision, the AUC approved the application from the Alberta Electric System Operator ("AESO") requesting new Section 502.10 of the Independent System Operator ("ISO") Rules, *Revenue Metering System Technical and Operating requirements*, and the associated terms and definitions.

Background

The AESO developed the final proposed new Section 502.10 and the associated terms and definitions that set out the requirements for the installation, operation, and maintenance of revenue metering systems in collaboration with stakeholders.

AUC Findings

Noting the absence of opposition to the application, and as no evidence to the contrary was submitted, the AUC was satisfied, based on the AESO's explanations, that the proposed amendments to Section 502.10 are not technically deficient; support the fair, efficient, and openly competitive operation of the market; and are in the public interest.

***Alberta Electric System Operator Approval of Proposed Amended Section 505.2 of the ISO Rules,* AUC Decision 26329-D01-2021**

ISO Rules - GUOC Refund

In this decision, the AUC approved the amendments to Section 505.2 of the independent system operator ("ISO") Rules, *Performance Assessment for Refund of Generating Unit Owner's Contributions*, proposed by the Alberta Electric System Operator ("AESO").

Background

The AESO submitted that it is required to include in the ISO tariff the generating unit owner's contribution ("GUOC"), which is meant to provide a long-term siting signal for generators to site in areas that would be most beneficial to load. Section 505.2 contains the performance assessment calculations for determining the refund of a GUOC to the legal owner of the generating unit. The currently approved version of Section 505.2 calculates a GUOC refund using rate system transmission service ("STS") contract capacity as an input.

The AESO submitted that following the recent approval of the ISO tariff, Section 505.2 required updates to include the AESO's new method for calculating the GUOC, the revised GUOC rates, and new terms for payment of the GUOC. The AESO explained this was needed as the ISO tariff changes require the extension of the GUOC to generating units that are not the subject of a Rate STS agreement with the AESO.

Under the proposed amended Section 505.2, the AESO would carry out the following process to assess GUOC refunds:

(a) Assess performance in January;

(b) Assess a performance factor of 100% or 0%, based on the metered energy of the generating unit during the performance year; and

(c) Continue to provide the legal owner of the generating unit with a preliminary refund assessment, identifying the inputs used to arrive at the GUOC refund.

The AESO submitted that the proposed amendments to are consistent with the statutory scheme, the approved ISO tariff, complete and self-contained, and drafted to be clear, concise, and cohesive to facilitate stakeholder's understanding.

The AESO submitted that the revisions incentivize market participants to provide the AESO with the best possible information. It submitted that this would: increase the AESO's confidence that a connection project will proceed due to financial obligations being triggered upon execution of the Rate STS agreement, where applicable; reduce the risk that system transmission facilities are built for connection projects that do not materialize and ensure those market participants with generation pay an appropriate amount of a GUOC. The amendments also remove duplication in the legislative scheme, aligning with the Government of Alberta's Red Tape Reduction initiative.

AUC Findings

Noting the absence of opposition to the application, and as no evidence to the contrary was submitted, the AUC was satisfied, based on the AESO's explanations, that the proposed amendments to Section 502.10 are not technically deficient; support the fair, efficient, and openly competitive operation of the market; and are in the public interest.

***Alberta Electric System Operator Needs Identification Document Application and ATCO Electric Ltd. Facility Application for Paintearth Wind Project Connection,* AUC Decision 23206-D01-2021**
Facilities - Wind Power

In this decision, the AUC approved the application for a needs identification document ("NID") from the Alberta Electric System Operator ("AESO") and the facility application from ATCO Electric Ltd. ("AE") to connect the Paintearth Wind Project to the Alberta Interconnected Electric System ("AIES").

Introduction and Background

On June 14, 2017, Paintearth Wind Project Ltd. ("Paintearth Wind") filed applications with the AUC for approval of the Paintearth Wind Project and the associated Lane Lakes 973S Substation. The applications were considered in Proceeding 22726.

The AESO subsequently filed a NID application, seeking approval to connect Paintearth Wind's Lanes Lake 973S Substation to the AIES. AE also filed facility applications for approval to meet the need identified by the AESO (the "Project"). Following the request from the AESO and AE, made pursuant to Section 15.4 of the *Hydro and Electric Energy Act*, the AUC combined the applications and considered them jointly as Proceeding 23206.

On December 4, 2018, the AUC granted Paintearth Wind Project Ltd.'s request to place Proceeding 22726 in abeyance. The Paintearth Wind Project was subsequently approved, with a total generating capability of 151.2 megawatts (MW), in Decision 22726-D01-2020 issued on January 22, 2020.

After the proceeding had been put in abeyance again on February 7, 2020, at the request of the AESO, the AUC resumed processing the connection project applications following the AESO's filing of an amendment to the NID on December 3, 2020.

Discussion

NID Application

The AESO had received a system access service request from Paintearth Wind to connect its Paintearth Wind Project to the AIES in the Paintearth area. Paintearth Wind requested a new rate Supply Transmission Service with a contract capacity of 150 MW and a new rate Demand Transmission Service with a contract capacity of 1 MW.

The AESO applied for an in-and-out connection to Transmission Line 9L93, which consisted of constructing a new substation, designated as the Pioneer 805S Substation, and altering existing Transmission Line 9L93 to connect it to the substation. Further, a new 240-kilovolt ("kV") transmission line, designated as Transmission Line 9L119, would be constructed to connect the new substation to Paintearth Wind's approved Lanes Lake 973S Substation.

The AESO indicated that it had developed one alternative that it preferred, as it was technically feasible and required less transmission development. However, Paintearth Wind indicated to the AESO that it did not wish to proceed with the alternative due to scheduling conflicts and that it would assume the additional costs of the applied-for project. The AESO consequently eliminated the preferred alternative from further study.

In response to an AUC information request, the AESO clarified that changing to the preferred alternative would delay the connection by six to eight months, which would not meet the business needs of Paintearth Wind. The AESO directed AE to file facility applications to meet the need identified and to assist the AESO in conducting a participant involvement program ("PIP") for its NID application.

Facility Applications

In its facility applications, AE proposed to:

- Construct a 240-kV switching station designated as Pioneer 805S Substation in Legal Subdivision 12, Section 23, Township 38, Range 15, west of the Fourth Meridian.
- Construct approximately 12 kilometers of single-circuit 240-kV transmission line, designated as 9L119, connecting the proposed Pioneer 805S Substation to Paintearth Wind's Lanes Lake 973S Substation.
- Construct approximately 100 meters of two new 240-kV single-circuit transmission lines, designated as 9L175 and 9L93, connecting the proposed Pioneer 805S Substation to the AIES.
- Redesignate a portion of single-circuit 240-kV Transmission Line 9L93 between the existing Tinchebray 972S Substation and the proposed Pioneer 805S Substation to Transmission Line 9L175.
- Construct a temporary bypass on existing Transmission Line 9L93.

AE conducted a participant involvement program ("PIP") in accordance with Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, and Hydro Developments.*

Findings

The AUC found that the NID application filed by the AESO contained all the information required by the *Electric Utilities Act*, the *Transmission Regulation,* and Rule 007.

The applied-for development was not the AESO's preferred alternative. Paintearth Wind requested that the Project be constructed as proposed and was prepared to pay the additional costs. The AUC found that the benefits of a smaller footprint associated with the AESO's preferred option did not offset the schedule and cost implications associated with it. The AUC found that it was reasonable for the AESO to apply for the development favored by AE because the other differences between the Project's footprint and the preferred alternative were minimal. The AUC approved the alternative preferred by Paintearth and accepted that Paintearth would pay the costs beyond the AESO's preferred, less costly alternative.

As no interested party opposed the approval of the NID application or demonstrated any deficiencies, the AUC considered the AESO's assessment of the need to be correct and approved the NID application.

***AltaLink Management Ltd. 2019 Projects Deferral Accounts Reconciliation Application,* AUC Decision 25913-D01-2021**
Rates - DACDA

In this decision, the AUC considered the application from AltaLink Management Ltd. ("AML") for the disposition of deferral accounts for 2019.

AML requested approval of the reconciliation of its 2019 direct assigned capital deferral account ("DACDA"). The AUC applied a reduction of 1.5 per cent to AML's total requested cumulative capital additions to December 31, 2019, of approximately $31.0 million because of imprudently incurred costs resulting from site security and permit and license delays associated with the ATCO Jasper Interconnection Project. The remainder of the amounts for reconciliation of AML's 2019 DACDA are approved, as filed.

AML was directed to file by April 30, 2021, an application complying with the directions and disallowances in this decision as part of either a separate compliance application or as part of its next general tariff application ("GTA").

Introduction

AML applied for approval and reconciliation of its 2019 completed projects, all 2019 trailing costs, and all other deferral account balances for 2019. Specifically, AML requested:

- A determination of reasonable project costs for projects completed in 2019 and orders disposing of the 2019 DACDA balance pertaining to direct assigned projects completed in 2019;

- The 2019 balances for other deferral accounts, including long-term debt, taxes other than income taxes and annual structure payments; and

- Revenue true-up for 2019 from AML's 2019-2021 GTA.

It also requested approval of $0.3 million in costs associated with DACDA, $2.7 million costs associated with other deferral accounts, and $0.1 million of associated carrying costs. AML added that revenue true-up results in a one-time charge to the Alberta Electric System Operator ("AESO") of $3.1 million, including payment of interest under Rule 023: *Rules Respecting Payment of Interest*.

AML requested 2019 final cost approval for a total of 98 transmission capital projects to be added to the rate base for total gross capital additions of $128.5 million and actual capital additions net of customers contributions of $89.2 million.

Discussion of Issues

Fortis-Initiated Projects

AML stated that FortisAlberta Inc. ("Fortis") might develop a project in response to a request from a connecting or connected customer, or Fortis as the distribution facility owner may initiate a project to address load, reliability, or distribution deficiency. Fortis sets the need for a project with the submission of a need for development ("NFD") to the AESO in both instances. The AESO tariff identifies that all costs of a connection project will be classified as either participant-related or system-related and provides the criteria to which the costs will be classified as participant-related or system-related. AML noted that the AESO, not AML, is the entity that identifies and determines the amount to be contributed by the market participant and the amount of AESO investment or system investment.

The AUC noted that, in Decision 22542-D02-2019, it had confirmed the AESO's central role being that of system planner and that there are statutory obligations of transmission facility owners ("TFOs") to comply with mandatory directions from the AESO. The AUC considered that determinations it makes regarding a TFO's prudence should fully account for the fact that the TFO is obligated to build its direct assigned project in accordance with the routing and specifications set out in the permits and licenses granted in respect of the project.

The AUC noted that the consideration of utilization of assets, as raised by the Consumers' Coalition of Alberta ("CCA") in this proceeding, is beyond the scope of the DACDA proceeding. The AUC also found that any examination by AML or another party on the technical requirements of direct assigned projects related to Fortis was outside the scope of DACDA proceedings.

Regarding AML's costs for the 2019 DACDA Fortis-initiated projects, the AUC was satisfied with AML's explanation of variances between costs provided in its project summary reports and actual capital additions for projects with 2019 in-service dates. The AUC noted that the capital additions to December 31, 2019, of these Fortis-initiated projects were below the initial proposal to provide service ("PPS") estimate and resulted in net capital additions of less than $5 million after customer contribution. The AUC found that the costs had been prudently incurred.

Salvage Costs

AML provided salvage costs incurred for the direct assigned projects for 2019, totaling $0.3 million. It explained that it uses the same control and oversight processes and procedures as it does with larger projects, and it often uses the same contractors for salvage work and larger project elements to lower the costs associated with salvage activities. AML's salvage costs of $0.3 million were approved as filed.

Affiliate Costs

AML confirmed that no costs included in the current application involved affiliate or non-arms-length transactions. The AUC accepted this confirmation from AML.

ATCO Jasper Interconnection Project (D.0576)

AML's ATCO Jasper Interconnection Project encompassed the construction of a transmission line and alteration of an existing substation to connect the municipality of Jasper and the surrounding areas within Jasper National Park to the Alberta Interconnected Electric System to serve new and existing electricity demand. This project did not meet the May 1, 2018 ISD planned in the PPS. AML requested the approval of capital additions net of salvage to December 31, 2019, for the project in the amount of $31,002,346, an increase of approximately $2.5 million from the PPS forecast and of $0.7 million from the PPS updated forecast. The AUC determined that not all the expenditures related to this project were prudently incurred.

(a) Foundation Construction and Danger Tree Removal

Geotechnical investigation, conducted after the initial PPS, determined that 60 out of 73 structures on the 530L Transmission Line would require helical screw pile foundations to support structure loading. While AML had identified less expensive alternatives, the AUC accepted that the construction of helical screw pile foundations was the only viable solution available in the circumstances.

The AUC was satisfied by AML's explanation that the trees in the common corridor shared with Fortis, who held a separate right-of-way, posed a danger to its newly built transmission line. It found the removal of the trees to be reasonable and that costs for tree removal had been prudently incurred.

(b) Fortis 25 kV Distribution Line

AML submitted that modifications to the 530L Transmission Line design and construction plan were required to address blowout concerns from an adjacent Fortis 25kV distribution line (the "Fortis line"). AML argued that the initial desktop survey based on geographic information system coordinates conducted by AML misidentified the actual location of the Fortis lines, which was not aligned with records used by AML to perform the initial survey. Additional costs of approximately $0.34 million were incurred to address concerns that the Fortis line could potentially swing into the AML 530L Transmission Line in wind events and could create a clearance violation.

The AUC accepted AML's clarification that the Fortis line was built correctly and that disposition records were incorrect. The preliminary desktop analysis results could not be confirmed until P&Ls were received and land access was obtained. The AUC further accepted that had the required transmission line design changes been added, the initial PPS estimate would have increased, as the need for the design changes and costs would have been identified.

(c) Security Costs

AML incurred additional costs for site security to prevent theft. Based on the risk assessment performed at the time of the PPS development, AML identified a cost impact of theft of materials of $51,470 with a probability of occurrence of 25 per cent. This represented a probability-adjusted impact to the project of $12,868. The AUC found that site security costs incurred were higher than the $51,470 estimated for site security of the project.

The AUC found it unclear why the PPS risk register was not updated to include a higher value assessment of the cost impact of theft to the project, given the value of materials and equipment stored on site. The AUC did not consider evidence filed by AML during reply argument to support higher security costs, as it determined this was improperly filed. Recovery of security costs claimed beyond $12,868 were disallowed.

(d) Permit and Licence Delay

AML attributed a delay of eight months in receiving P&Ls for the project to an AUC public hearing in Proceeding 22125. Because of the timing of the P&L approval, AML rescheduled the 530L Transmission Line construction from the winter season of 2017-2018 to the winter of 2018-2019, which resulted in additional costs.

While the AUC acknowledged AML's efforts to facilitate a fast process in Proceeding 22125, it noted that as a sophisticated utility, AML should be aware that the issues of Proceeding 22125 required approvals and was likely to be public and take time. The AUC determined that AML should have planned more precisely and accounted for the likelihood of a public process in Proceeding 22125. Additional costs related to P&Ls were therefore not all prudently incurred. All imprudently incurred costs were considered in the 1.5 per cent general reduction to AML's total requested cumulative capital additions to December 31, 2019.

Areas not Individually Addressed

AML requested approval of costs for 98 transmission direct assigned capital projects completed in 2019, orders disposing of the 2019 DACDA balance, and 2019 balances for other deferral accounts including long-term debt, taxes other than income taxes, and annual structure payments (the "other deferral accounts").

The AUC found that those projects and associated costs not specifically discussed in previous sections were prudently incurred and approved them as filed.

The AUC noted that AML's 2016-2018 DACDA compliance proceeding (Proceeding 26278) was ongoing, which may have an impact on costs subject to approval in the current proceeding. AML was directed to identify any findings related to the Proceeding 26278 decision that are applicable to its 2019 DACDA and to true up any impact as part of either a separate compliance application or as part of its next GTA.

Subject to the findings and directions in this decision and any impacts to 2019 DACDA amounts that may arise from Proceeding 26278 related to AML's 2016-2018 DACDA compliance proceeding, the AUC approved AML's 2019 DACDA, as filed.

AltaLink Management Ltd. 2021-2023 Tariff Refund, AUC Decision 26248-D01-2021

Tariff - Rider C

In this decision, the AUC directed AltaLink Management Ltd. ("AML") to adjust its 2021 tariff by the amount of $230 million, which results in a net 2021 tariff reduction in the amount of $223,512,781 to be implemented effective April 1, 2021. This net tariff reduction results in a revised 2021 net monthly tariff of $45,851,942 for April through December 2021.

The AUC concurrently directed the Alberta Electrical System Operator ("AESO") to utilize Rider C to pass through the net 2021 tariff reduction of $223,512,781 in the second quarter of 2021. This would provide Alberta ratepayers with immediate, albeit temporary relief in 2021. The AUC further granted the AESO relief from Subsection 2(3) of Rider C such that the AESO is not required to publish the $223,512,781 credit at least 30 days prior to the beginning of the second quarter. This exemption permits the AESO to amend any existing published amounts as needed.

APEX Utilities Inc. Code of Conduct Regulation Compliance Plan Amendments, AUC Decision 26302-D01-2021

Code of Conduct Compliance Plan

In this decision, the AUC considered the application from Apex Utilities Inc. ("AUI") for approval of changes to its *Code of Conduct Regulation* Compliance Plan. The AUC approved the applied for amendments in part.

Background

AUI filed its application pursuant to Section 32 of the *Code of Conduct Regulation* ("*CCR*"). As of November 12, 2020, the *Code of Conduct Regulation* was amended to remove or update certain required sections from utilities' *Code of Conduct Regulation* compliance plans.

AUI sought approval of changes to its compliance plan to reflect removal and amendments pursuant to the requirements of the amended *CCR*. AUI also made minor administrative changes, including changes to the numberings of sections, for consistency with the removed sections.

AUI submitted that changes to its compliance plan were minor and made to reflect the changes to the *CCR.* AUI made the proposed changes in an amended version of its compliance plan.

Findings

The AUC was satisfied that the removal of sections and other administrative amendments made by AUI, as set out above, would be consistent with continued compliance with and sufficiently address the requirements of the *CCR*.

The AUC was concerned that the compliance plan contained no provision for the creation and retention of the records required for the AUC to carry out its future audits as required under Section 40 of the *CCR*. Therefore, the AUC directed AUI to include a specified text under 'PART 8 COMPLIANCE AUDIT' in its *CCR* Compliance Plan, setting out how AUI will ensure that the necessary files are kept.

The AUC directed that AUI filed the revised compliance plan by April 7, 2021. Effective April 1, 2021, the AUC approved AUI's *CCR* Compliance Plan, with the changes directed by the AUC.

ATCO Electric Ltd. Approval of the Revised Palisades Sale Offering, AUC Decision 26078-D01-2021
Power Plant - Sale Offering

In this decision, the AUC approved a sales process proposed in an application from ATCO Electric Ltd. ("AE") for a revised sales offering for isolated generating units located at the Palisades Power Plant. AE proposed two alternative sales processes. The AUC approved Sales Process B as filed.

AUC Findings

Section 26 of the *Isolated Generating Units and Customer Choice Regulation* ("*IGUCCR*") concerns the circumstances under which an isolated generating ("IG") unit that is no longer required to provide electric energy can be sold by the owner of the generating unit. In cases where the owner decides to sell the generating unit, the sale must be conducted in accordance with Part 2 of the *IGUCCR*, which sets out that the AUC must determine that the sales offering meets the criteria set out in Section 17 of the *IGUCCR*. Specifically, the sale offering is to be widely publicized and conducted in a manner that does not make the offering less attractive or discourage or restrict potential bids that could be made in response to the offering.

Further, Section 18(1) of the *IGUCCR* requires that before advertising a sale offer, the owner of the generating unit must submit to the AUC the sale offering and a proposal as to how the sale offering complies with Section 17 of the regulation. Section 18(2) also requires that, if on reviewing the proposal, the AUC is satisfied that Section 17 will be complied with, the owner must proceed with the sale offering in accordance with the proposal.

In its application, AE requested the following amendments to the Palisades Power Plant sale offering approved in Decision 24598-D01-2019 under "Modifications to the sale process":

> In the alternative, approval of a bundled sales process (Sales Process B), whereby the IG Assets are bundled and sold in 10 (sic) separate asset packages." Under Sales Process B, "bidders will be permitted to submit separate bids on one or more of the 11 assets package(s)," and ATCO "will dismantle the IG Assets

> and bundle the IG Assets into 11 groupings of equipment associated with individual generating units as well as groupings of other related IG Asset facilities equipment.

AE further requested that two freight containers, which AE would use to provide storage for the Jasper Interconnection facilities at the Sheridan substation site, be removed from the listing of plant and equipment identified in its application in Proceeding 24598.

While the AUC appreciated that AE stated that it expects Sales Process A to be more cost-efficient than Sales Process B, the AUC was concerned that Sales Process A has the potential to discourage certain parties from participating in the sale offer. In particular, with respect to Sales Process A, AE acknowledged that potential buyers who are only interested in some of the equipment might be less likely to participate in Sale Process A. AE also stated that Sale Process A would require the purchaser to be responsible for the removal of the "IG Assets", which may discourage smaller potential buyers or interested parties from participating. AE further noted that more stringent Parks Canada guidelines must be followed for the removal of the "IG Assets", which may also discourage potential buyers from participating in Sales Process A.

While the AUC found that the sale offering and proposal outlined by AE in Sales Process B complies with the provisions of Section 17 of the *IGUCCR*, the AUC wished to address two issues explored concerning the request for quotations ("RFQ") documentation that AE filed for Sales Process B:

(a) AE stated that "the Owner may, in its sole discretion … choose to shortlist some but not all bidders onto a preferred candidates list." While the AUC understood that it might be commercially reasonable to shortlist bids, for transparency, the AUC directed AE, in a future application made under Section 20 or 21 of the *IGUCCR* with respect to this sale offering, to provide details showing all parties that submitted a bid for any of the asset packages, the associated bid amounts and supporting information and reasons for why any party or bid was shortlisted (or not shortlisted).

(b) AE stated that "the Owner may, in its sole discretion, amend the RFQ at any time prior to the RFQ Closing Date and Time…." In response to an AUC information request ("IR"), AE clarified that this clause would allow it to make amendments to the RFQ in response to unforeseen circumstances (with prior approval from the AUC) without having to collapse the RFQ. In the same IR response, AE's also requested approval to extend the Palisades RFQ closing date by up to two weeks if two or more bidders request an extension.

The AUC agreed that a certain amount of flexibility in the RFQ would be beneficial to avoid any inefficient amendments and delays to the Palisades sale process. Accordingly, the AUC approved AE's request to extend the Palisades RFQ closing date by up to two weeks if two or more bidders request an extension to the RFQ's closing date.

The AUC approved the sale offering and proposal outlined in Sales Process B for the sale of the Palisades IG units as filed and rescinded Decision 24598-D01-2019. AE was directed to proceed with the sale offering for the Palisades IG units in accordance with the proposal outlined in Sales Process B and the draft sale offering advertisement.

ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application, **AUC Decision 24964-D01-2021**
Rates - General Tariff Application

This decision reflects the determinations of the AUC regarding head office rent and the shared services initiative in the 2020-2022 general tariff application ("GTA") filed by ATCO Electric Ltd. ("AE"). In this decision, the AUC panel found that not all of the forecast revenue requirements related to head office rent and the shared services initiative are reasonable and has revised or denied these amounts. The findings regarding the remainder of AE's forecast revenue requirements for the 2020-2022 test period are issued in Decision 24964-D02-2021.

In proceedings 25663 and 24964, similar issues were raised, and similar evidence was filed by ATCO Pipelines and AE concerning ATCO Park - head office rent and the shared services initiative. The submission of similar evidence on the shared services initiative was directed by the AUC in Decision 23793-D01-2019.

ATCO Park – Head Office Rent

Head office costs are related to functions such as corporate governance and financial and administrative services that cannot be directly charged to subsidiaries. The applied-for square footage, lease, and operating rates for ATCO Park to be included in head office rent costs allocated to ATCO Pipelines' and AE's revenue requirements for their respective test periods were set out in the AUC decision.

Lease and Operating Rates

In support of the applied-for lease rates, ATCO Pipelines and AE provided a report prepared by Altus Group in which it recommended lease rates of $29.00 to $31.00 per square foot in August 2017 and $28 to $30 per square foot at January 2020, on an "as is" basis, for ATCO Park. ATCO Pipelines submitted that the Altus Group report is still reflective of market conditions and noted that the AUC had found that the time for assessing the fair market value ("FMV") of ATCO Park's head office rent was August 1, 2017.

AE further argued that the correct determination of the FMV for the ATCO Park lease rate as at August 1, 2017, is important because it is the baseline for the escalation factor of $1 per square foot every third year that, in its view, the AUC approved in Decision 24805-D02-2020, the compliance filing to AE's 2018-2019 GTA.

The AUC disagreed with AE's description of the findings in Decision 24805-D02-2020 and the asserted significance of the FMV for the ATCO Park lease rate as at August 1, 2017. The AUC denied the application of the proposed rent calculator in that decision and noted that its comments in that decision do not fetter the assessment of the reasonableness of the ATCO Park lease rate costs in the forecast test years under consideration in the current proceeding.

Because of the lack of a formal lease or sublease for AE or ATCO Pipelines, the AUC considered that these utilities retain discretion to negotiate their rental rates. The AUC considered evidence of lease rates filed in proceedings 25663 and 24964 addressing the impact of COVID-19, the accompanying economic downturn on lease rates over the current test periods. The AUC did not find convincing evidence to support a change in previously approved lease rates of $20 per square foot. It, therefore, found it reasonable to continue this rate for each of 2020, 2021, and 2022 for AE.

For operating rates, the AUC approved a continuation of the previously approved $0.50 per square foot escalator per year. Accordingly, operating rates per square foot of $17 for 2020, $17.50 for 2021, and $18 for 2022 were approved for AE.

Square Footage

The AUC approved the head office square footage of 122,049 applied for in this proceeding. In consideration of regulatory efficiency and the public interest, the AUC will no longer examine head office square footage in every GTA and GRA when the impact on revenue requirement is potentially immaterial.

Shared Services Initiative

As part of the shared services initiative, ATCO Pipelines AE and several other ATCO group entities identified common shared services functions that provide standardized internal services for all of the ATCO group of entities on a cost-recovery basis. To allocate shared service costs between the various entities, allocation methods, including direct charging, using casual allocation factors, or using a general cost allocation formula, were proposed. In Decision 23793-D01-2019, the AUC approved ATCO Pipelines' shared services costs as filed on an interim basis.

Shared Services Functions and Allocators

Fourteen functional groups were transitioned to the share services model. The innovation and Indigenous, government relations and sustainability ("IGRS") groups were identified as discreet functional groups for the first time in proceedings 25663 and 24964. Utilities and Interveners disagreed on whether the innovation, government, and sustainability functions would provide value to the utilities and customers.

The AUC recognized the importance of the Indigenous relations component of the IGRS function, such as increasing focus and awareness, educational programs and training, and more. The AUC also recognized the government relations' group efforts in providing support and guidance to ATCO Pipelines and AE on strategic government initiatives and plans, and it considers innovation to be a legitimate activity for regulated utilities.

The AUC was also satisfied that the allocator of the number of invoices proposed for the accounts payable; headcount, proposed for human resources; space square footage, proposed for facilities management; the number of vehicles, proposed for fleet services; and 50 per cent operating costs & 50 per cent net book value of IT assets, proposed for IT services, were appropriate. The AUC approved the proposed shared services allocators of these groups for the 2020-2022 GTA and 2021-2023 GRA periods.

The AUC found that the general cost allocator ("GCA") method was the most appropriate allocation method for the supply chain, financial services (not including accounts payable), regulatory, project management, innovation, and IGRS functions. While the AUC approved the use of the GCA, it noted that the evidence presented by ATCO Pipelines and AE in support of the GCA had limitations.

Because of these limitations, the AUC determined that there was a need for further testing to confirm the reasonableness and accuracy of the GCA allocation methodology and to ensure the reasonableness of the associated GCA allocation methodology as between regulated and non-regulated entities. AE and ATCO Pipelines were directed to each conduct an analysis that examines direct charging (or some reasonable and defensible proxy of effort or time) for the supply chain and financial services (excluding accounts payable) functional groups and to produce a cost allocation for each ATCO group entity, for both functional groups (including each financial services subfunction). This information was to be filed in their next GTA and GRA, respectively, following the completion of the requested analysis.

Further, the AUC directed that AE use the 2019 actual variable in place of the 2018 actual variable as inputs into the shared services allocation formulas in its compliance filing to maintain consistency between proceedings 24964 and 25663. The shared services allocations were also to be adjusted accordingly.

The AUC also took issue with the clarification of the weighting between IT annual operating costs and IT asset net book value used in the IT services allocator. The AUC found that the evidence submitted by AE did not demonstrate that IT annual operating costs and IT asset net book value were weighted equally. In their respective compliance filings, AE and ATCO Pipelines were directed to recalculate the IT services allocator with net revenues, total assets, and total labor costs being weighted equally and to make the necessary adjustments to the IT services cost allocation.

The AUC was concerned with deferral accounts. AE and ATCO Pipelines were directed to, in their respective compliance filings, adjust their shared service cost allocations by including deferral account revenues in calculating net revenues for the GCA allocator.

In Proceeding 24964, AE stated that Canadian Utilities Limited sold Alberta PowerLine in 2019 and that Alberta PowerLine was consequently removed from the shared services allocation formulas to reflect this sale. The AUC directed AE and ATCO Pipelines to confirm that shared services employees are no longer providing services to Alberta PowerLine and that no direct or indirect services will be provided to Alberta PowerLine on the 2020-2022 GTA or the 2021-2023 GRA test period.

Shared Services Costs and FTEs

The AUC determined that insufficient evidence was submitted to support the forecast shared services FTE increases throughout 2020-2023. The AUC found it difficult to review the shared services forecasts provided by AE and ATCO Pipelines, given the frequent corporate reorganizations at ATCO Ltd., the inability of ATCO Pipelines, and AE to provide accurate information on historical shared services costs and FTEs, and the inconsistent FTE forecasts provided by AE. The AUC noted it could not rely on the forecasts provided by AE and ATCO Pipelines.

The AUC was concerned with the number of FTEs allocated to AE and ATCO Pipelines for services provided by the government relations and sustainability groups. The AUC found that the inclusion of these two regulated rates provides limited benefits to the utilities and their regulated customers. The AUC found it unclear how the extent of the applied-for increase in IGRS FTEs is required for ATCO Pipelines and AE to provide safe and reliable services to Alberta ratepayers.

AE and ATCO Pipelines were further directed to, in their compliance filings:

(a) apply a zero per cent vacancy rate to its shared services FTEs, and to make all the necessary salary, benefit and escalation adjustments to reflect the AUC's direction above on shared services FTEs;

(b) not offset the impacts of the reduction to capital FTEs with an increase in contractor costs;

(c) not adjust its capitalization policy with respect to FTEs; and

(d) clearly identify how these various directions are complied with by showing each individual adjustment and the associated impact on shared services costs.

ATCO Pipelines had noted that the 2019 IT Asset NBV inadvertently included construction work in progress ("CWIP") related to all intangible assets for all entities. It noted that the revenue requirement impact would be approximately $150,000 per year and will be updated in the compliance filing to the GRA Decision. The AUC directed ATCO Pipelines to make the corresponding revisions in its compliance filing. AE was directed to make the same revisions if the same error had been made in its 2020-2022 GTA.

AUC Order

The AUC ordered that ATCO Electric filed its 2020-2022 transmission general tariff application compliance filing to reflect the findings, conclusion, and directions of this decision on a date to be confirmed by the AUC in Decision 24964-D02-2021.

***ATCO Electric Ltd. 2020-2022 Transmission General Tariff Application,* AUC Decision 24964-D02-2021**
Rates - GTA

This decision set out the determinations of the AUC regarding the transmission general tariff application (application or "GTA") filed by ATCO Electric Ltd. ("AE"). Not all forecast revenue requirements for the 2020-2022 test period were determined to be reasonable.

Introduction and Background

The breakdown of the 2020-2022 revenue requirements and other forecast costs reflected AE's September 28, 2020, application update for material impacts, including impacts of the COVID-19 pandemic and economic downturn. The revenue requirements showed an annual increase of 4.7 per cent, to 724.2 million, in 2020, a decrease of 0.7 per cent, to 718.8 million in 2021, and an increase of 1.9 per cent, to $732.2 million in 2022. AE requested approval of additional opening rate base additions of approximately $0.7 million above the amounts forecast in its 2018-2019 GTA.

Common Group Full-Time Equivalent Allocators

The AUC's findings on AE's shared services full-time equivalents ("FTEs") are set out in Decision 24964-D01-2021. AE requested approval to transition 18 functions to the common group model and proposed a method of allocating FTEs and costs between AE Transmission and AE Distribution for each common group function.

For the allocators proposed for the field health and safety and the service operations director functions, the AUC was satisfied that they were consistent with the common group allocators previously approved in Decision 22742-D01-2019. The AUC approved the proposed allocation methodologies.

With regard to FTEs, the AUC found that the submitted evidence did not support the approval of the requested 32.6 “Differences between forecast and actual” FTE additions for 2021 and 2022. AE was direct to use its internal 2019 actual FTEs as the approved base level FTE complement for all test years. Notwithstanding these findings, the AUC approved AE’s incremental additions of 3.7 capital and 6.1 operation and maintenance (“O&M”) FTEs in 2020, 5.0 capital and 3.4 O&M FTEs in 2021, and 1.5 capital FTEs in 2022.

With regard to vacancy rates, the AUC found that a vacancy rate of zero per cent is reasonable and accordingly directed AE to apply a vacancy rate of zero per cent to its approved FTE complement.

On labor reporting, the AUC found that AE’s proposed headcount method is not a reasonable alternative to the established FTE allocation method for labor reporting purposes. AE was directed to provide its labor requirements and labor reports via the established and long-standing FTE method.

The applied-for severance costs and severance cost forecast were approved as filed.

For inflation for in-scope labor, AE was directed to incorporate the approved 1.90 per cent for 2020 and 1.75 per cent for 2021. AE was directed to apply a 1.8 per cent in-scope labor inflation rate for 2022.

The AUC approved out-of-scope labor inflation rates of zero per cent for 2020, 0.8 per cent for 2021, and 1.8 per cent for 2022. AE was directed to use “other” and contractor inflation rates of 1.2 per cent for 2020, 0.8 per cent for 2021, and 1.8 per cent for 2022.

Operation and Maintenance Costs

The AUC approved telecommunication service agreements as filed for the test years. The AUC also approved forecast costs for compliance activities for Alberta Reliability Standards, as well as cybersecurity and critical infrastructure costs. Taxes other than income were approved as filed.

The AUC approved a disaggregated method of administering the variable pay program (“VPP”) effective January 1, 2020. The AUC found that this facilitated that the closing balance at the end of each new test period year equals the applied-for VPP and that VPP accounts can be maintained as close to zero as possible where actual and approved information was not yet finalized.

AE’s Mid-Term Incentive Program (“MTIP”) raised concerns regarding the need for additional incentive programs for executive positions, considering the existing pay level of those positions. AE was directed to remove its forecast MTIP costs for the test period in its compliance filing.

AE had forecast decreasing costs for vegetation management because of changing its vegetation management method. The AUC found that the unpredictable nature of and forecast risk associated with the Vegetation Management Program still justified maintaining this reserve account.

Depreciation

Examination of Average Service Lives

AE requested approval of a decreased service life for substation equipment. The AUC rejected this request and directed AE to use its currently approved 53-R3 for USA 353.00 – Substation Equipment in its compliance filing.

The AUC approved the implementation of a 50-R3 for the USA 353.02 – HVDC Substation account in its compliance filing.

AE proposed to change the life-curve parameters for the communications account from the currently approved 25-R2 to 25-R3. The AUC found this to be reasonable and approved the proposed life-curve.

AE proposed to decrease the life-curve parameters for USA 354.00 account from the currently approved 65-R4 to 60-R3. The decrease proposed by AE was approved.

For USA 354.01 – Towers - ISO Rule 502.2 Compliant, the AUC found an increase of the service life from 65 to 67 years to be reasonable. Although AE requested a curve parameter of R2.5, the AUC did not find sufficient reasons to treat this account differently than account USA 354.00, for which a curve parameter of R3 had been requested. AE was directed to implement a life-curve of 67-R3 for this account in its compliance filing.

Regarding account USA 355.00 - Poles, AE was directed to maintain the life-curve of 60-R2 for this account.

Examination of Net Salvage Percentages

AE proposed to increase the net salvage percentage for USA 353.00 – Transmission Substation from the currently approved -15 per cent, to -20 per cent. The AUC approved the applied for increase.

The AUC found it was reasonable to mirror the net salvage percentage for USA 353.00 (AC substations). The AUC approved a net salvage of -20 per cent for USA 353.00 – Transmission Substation.

AE request to increase the negative net salvage percentage for USA 354.00 - Towers was denied. It also denied a request to increase the negative net salvage percentage for USA 354.01 - ISO Rule 502.2 compliant towers.

For USA 355-Poles, the AUC found that the approved -90 per cent net salvage remained reasonable.

<u>Affiliate Transactions and Revenue Offsets</u>

Revenue offsets that form part of a revenue requirement include amounts related to facility charges, affiliate revenues, services to outside parties, and other revenue. The AUC approved the forecast revenue offset as filed.

<u>Opening Rate Base and Capital Projects</u>

AE's Transmission Capital Maintenance ("TCM"), direct assigned capital, and isolated generation projects did not raise any issues and were found to reflect applicable directions issued by the AUC. The AUC approved the 2020 opening rate base amounts for these categories. After briefly examining issues raised by interveners, AE's General Property and Equipment 2020 opening rate base was approved as filed.

Transmission Capital Maintenance Projects

AE's TCM Program includes asset replacement and maintenance projects and is designed to manage transmission assets in accordance with life cycle asset strategies. The AUC approved the forecast costs for the capital projects apart from Wildfire Mitigation and Grid Resiliency, Isolated Generation Projects, and the ATCO 9L32/66 Line Move.

Regarding the proposed new Wildfire Mitigation and Grid Resiliency Project ("WMP"), aimed at addressing increasing wildfire-related risks observed in Alberta and in North America, issues were raised regarding the level of risk identified by AE. The AUC denied the WMP, finding that increased wildfire risks can be addressed within existing TCM programs and projects.

AE requested approval of capital expenditures for the maintenance and capacity needs of AE's isolated generation assets in the amount of $12.6 million in 2020, $17.0 million in 2021, and $8.5 million in 2022.

The AUC reviewed the information with respect to AE's isolated generation projects. With the exception of three projects discussed in the decision, the AUC was satisfied that the forecast costs for the isolated generation projects, as applied for by AE, were reasonable and approved them.

Regarding fuel costs associated with isolated generation projects, AE was directed to update its fuel cost forecast in the compliance filing.

AE requested the relocation of two transmission lines so that Canadian Natural Resources Limited could mine and develop its resources in a certain area. The AUC found that the benefits of the line relocation outweighed the relocation costs to ratepayers of $41.5 million and approved the allocation of these costs to the system.

General Plant and Equipment IT Projects Forecast Expenditures

The AUC approved the forecasted General Plant and Equipment IT capital project expenditures and additions.

Direct Assigned Capital Projects

AE forecast the capital expenditures for its direct assigned capital projects to be $95.9 million, $182.8 million, and $172.8 million in 2020, 2021, and 2022, respectively. No concerns were raised regarding the direct assigned forecast capital expenditures, except for forecast expenditures for the CETO Project. AE forecast capital expenditures for the CETO Project of $2.8 million in 2020, $49.3 million in 2021, and $57.7 million in 2022, for a total of $109.8 million in the test period.

The AUC observed that the CETO Project had experienced several delays. AE was directed to reduce its forecast expenditures for the 2020-2022 test period by 50 per cent of the applied for $109.8 million and to update the applicable schedules.

Project Identification

AE indicated that it would adopt a "written description of the categorized appropriation grouping" on documentation included in its GTAs, such as the application, GTA schedules, and business cases. The AUC found it necessary to maintain the ability to follow a capital project through all stages of its construction as presented in AE's GTAs and Rule 005 filings. Because project stages often span more than one test period, there is a risk that project identification relying on a project name alone could result in confusion and categorization of costs to the wrong project. Accordingly, AE was directed to continue using the approved numbering and identification scheme and strategy for its capital projects.

<u>Financing and Income Taxes</u>

AE was directed to include a deemed common equity ratio and return on equity of 37 per cent and 8.5 per cent on a final basis, for the years 2021 and 2022, respectively, to reflect findings in decision 24110-D01-2020 and 26121-D01-2021, the 2021 as well as the 2022 Generic Cost of Capital proceeding. The AUC accepted AE's forecast of federal and of provincial income taxes for 2020-2022. These forecasts had been derived using the future income tax method and flow-through method, respectively.

Provincial Corporate Income Tax

The AUC found the statutory rate deferral account true-up mechanism would result in an unnecessary regulatory process to true up to a provincial corporate income tax rate that is now known with certainty, at a cost to ratepayers. AE was directed to update its forecast income taxes to reflect the current provincial corporate income tax rate of eight per cent effective July 1, 2020, in its compliance filing.

Long-Term Debt Rates

As AE's external financing requirements are obtained through CU Inc., the AUC found this to be the best available information in determining reasonable forecast 2022 long-term debt rates. Accordingly, AE was directed to use a 2022 long-term debt rate of 2.60 per cent in its compliance filing.

Preferred Shares – Deemed Redemption

AE stated that two of its three preferred share issues would be subject to rate resets during the 2020-2022 test period. It forecast its series four and V reset rates at 3.37 per cent (currently 2.24 per cent) and 5.00 per cent (currently 4.6 per cent), respectively.

The AUC did not approve AE's forecast 2022 Series V preferred share reset rate of 5.00 per cent and directed AE to maintain the Series V preferred share rate of 4.60 per cent on a placeholder basis in its compliance filing.

Escalation Mechanism 2023 and 2024

AE requested approval of an I-X escalation mechanism. The mechanism would allow AE to choose, at its discretion and at some future date, whether to apply an inflation factor (I) and a productivity factor (X) to its approved 2022 revenue requirement, thereby setting its revenue requirement for the year 2023, or for the year 2023 and then subsequently 2024, without the need for a full cost of service application.

Despite possible efficiency benefits, the AUC denied the applied for escalation mechanism. The AUC determined that the mechanism creates an unreasonable risk to customers and none to AE. It did not accept the statement that both AE and customers could benefit if the escalation mechanism was used and would be no worse off if it remained unused.

***ATCO Gas Application for Approval of Changes to ATCO Gas's Gas Settlement Process and Retailer Terms and Conditions for Gas Services*, AUC Decision 26013-D01-2021**

Gas Utilities - Terms and Conditions

In this decision, the AUC approved changes made by ATCO Gas to its gas settlement process, associated changes to its Retailer Terms and Conditions ("T&Cs") for Gas Distribution Service, and adjust its tolerance zones based on distribution system balancing requirements rather than maintaining alignment with those of NGTL. The AUC denied the request to recover its Imbalance Reporting Information System ("IRIS") upgrade costs through its Load Balancing Deferral Account ("LBDA"). It directed ATCO Gas to cover these costs using the indexing (I-X) mechanism under performance-based regulation ("PBR").

Details of the Application and Procedural Background

ATCO Gas applied to change from an "in kind" to a financial settlement process. ATCO Gas would use the average gas price on the day of use to determine retailers' financial accounts. This change would eliminate the need for retailers to purchase gas from or sell gas to ATCO Gas to balance their accounts. To implement the changes, ATCO Gas proposed changes to its Retailers T&Cs for Gas Distribution Service and to adjust its tolerance zones based on distribution system balancing requirements rather than maintaining alignment with those of NGTL. As well, ATCO Gas must upgrade its IRIS. The costs to perform this upgrade were estimated at $170,000, and it requested recovery of these costs through its LBDA. ATCO Gas advised that its support for the proposed changes was contingent upon the ability to recover these costs.

Discussion of Issues and AUC Findings

Changes to the Gas Settlement Process Methodology

The AUC determined that the "in kind" settlement process employed by ATCO Gas at the time of the application is vulnerable to price differentials due to the lag between the initial gas allocation from ATCO Gas to retailers and the settlement adjustment.

The AUC supported the implementation of the new settlement process. It found that the new settlement process would eliminate the price fluctuations between the day-of-use price and the prices used for each of the settlement intervals. The new settlement process, the associated changes to ATCO Gas's Retailer T&Cs for Gas Distribution Service, and the removal of the requirement for its imbalance window to match the transmission balance zone of NGTL to effect this change was approved.

Recovery of the IRIS Upgrade Costs

IRIS is ATCO Gas's program that contains retailer accounts and is used by retailers and ATCO Gas to monitor the daily imbalance between gas supply and customer consumption, to issue gas supply nominations, and to administer imbalance purchases/sales. ATCO Gas estimated that the IRIS upgrade costs to implement the process change are approximately $170,000 and sought to recover those costs through its LBDA.

ATCO Gas stated that the IRIS upgrade costs should not be recovered through the I-X mechanism under PBR because the change is not required to maintain service quality for its customers or to generate efficiencies for ATCO Gas. Rather, because the proposed changes are for the benefit of retailers and their customers, the decision to recover the costs through the LBDA would be consistent with cost causation principles.

The AUC found that recovery of this IRIS upgrade should be covered by the I-X mechanism under PBR. The AUC noted that ATCO Gas submitted no evidence to support why it could recover the IRIS upgrade costs for previous updates under the I-X mechanism but was now seeking to recover the $170,000 IRIS upgrade costs outside of the PBR funding mechanism.

Investigation of ATCO Gas' Forecasting Methodology

The Consumers' Coalition of Alberta ("CCA") raised concerns regarding the estimations that make up ATCO Gas' LBDA balance. Rather than randomly fluctuating, the forecasts tended to be only in one direction, leading to retailers being overcharged.

The AUC noted that if ATCO Gas' initial forecasting methodology is flawed in a way that results in bias against the gas retailers, the proposed changes to the gas settlement process may not fully address significant overcharges of the retailers. It noted that it did not have the evidence to determine if the forecasts are biased, as alleged by the CCA. However, the AUC found a review of the methodology to be warranted.

To review the efficiency of the changes proposed to the settlement process, the AUC ordered that ATCO Gas submit a review of the operation of the financial gas settlement process one year after its implementation. This review should demonstrate if the changes have eliminated the issues surrounding retailer cash flow volatility and have removed potential forecasting bias against retailers. ATCO Gas was also required to provide a review of the accuracy of its daily forecast settlement system.

Order

The AUC directed ATCO Gas to implement the changes approved in this decision as soon as practicable and no later than the first day of use for the first of the month following the date of this decision. The financial gas settlement process would then commence in the corresponding Settlement Run 1 based on that day of use.

***ATCO Gas and Pipelines Ltd. South Airdrie Lateral Pipeline Resumption,* AUC Decision 26319-D01-2021**
Facilities - Gas Supply

In this Decision, the AUC approved the applications from ATCO Gas and Pipelines ("ATCO") for an amendment to resume line 1, under Licence 56256 and line 3, under Licence 60905.

Introduction and Background

In Decision 24174-D01-2019, the AUC had approved, with conditions, applications 24174-A001 and 24174-A002 filed by ATCO to transfer two existing pipelines, line 15 under Licence 15140 and line 1 under Licence 56256, from Steelhead Petroleum Ltd to ATCO and found that the pipeline acquisition was the best alternative to meet the identified need to increase the security of natural gas supply to the city of Airdrie.

ATCO filed Application 26249-A001 requesting approval to perform a pipeline split of line 1 und Licence 60905 into lines 1, 2, and 3; and amend the hydrogen sulfide concentration of the pipeline from 2.5 mol/kmol to 0.0 mol/kmol. After the split, line 1 would be abandoned in place, line 2 would be transferred to ATCO Gas to be operated at low-pressure distribution service, and line 3 would be amended from discontinued to operating status. This was approved in Decision 26249-D01-2021.

To date, neither line 3, under Licence 60905, nor line 1, under Licence 56256 had been operated by ATCO; both lines had been discontinued by their former owner, Steelhead Petroleum Ltd.

In this proceeding, ATCO proposed to amend line 3, under Licence 60905 and line 1, under Licence 56256, from discontinued status to operating status, to allow ATCO to place these pipelines into high-pressure service.

AUC Findings

The AUC accepted ATCO's commitment that all risks that required mitigations would be completed. The AUC found that the potential environmental impacts of the South Airdrie Lateral project were sufficiently addressed in ATCO's environmental evaluation report and accepted ATCO's commitment to implement the recommendations presented in that report to reduce the risk of potential adverse environmental impacts associated with the South Airdrie Lateral project.

The AUC noted that the applied-for amendments were required to allow ATCO to place the acquired pipelines into high-pressure service as was intended to provide security of natural gas supply to the city of Airdrie. The AUC also found that the applied-for license amendments would be in the public interest in accordance with Section 17 of the *Alberta Utilities Act.* The AUC approved the applications.

***ATCO Gas and Pipelines Ltd. 2020 General Rate Application Phase II Compliance Filing,* AUC Decision 26283-D01-2021**
Rates - Compliance Filing

In this decision, the AUC considered ATCO Gas and Pipelines Ltd. ("ATCO")'s compliance with the AUC's directions issued in Decision 25428-D01-2021 regarding ATCO Gas' 2020 general rate application Phase II.

Compliance with AUC Directions

The AUC was generally satisfied that ATCO had complied with the 14 directions and associated findings made in Decision 25428-D01-2020. The AUC considered matters that arose as a result of ATCO's responses.

Alternative Technology and Appliance Delivery Service Rate Group

In Decision 25428-D01-2020, the AUC issued Direction 5 regarding ATCO's Alternative Technology and Appliance Delivery Service ("ATA") Rate. It directed ATCO to provide a detailed analysis of the ATA rate as part of its performance-based regulation (“PBR”) adjustment filing one year following the ATA rate implementation and then in its next Phase II application.

In response, ATCO provided information regarding the riders applicable to the ATA rate, including a newly proposed change from the original application. ATCO proposed to exclude the weather deferral account (“W”) rider. ATCO explained that the ATA rate group’s natural gas usage requirements are not expected to be temperature sensitive, as these customers will be using alternative heating systems and natural gas only for non-space-heating appliances. It stated that, therefore, the ATA rate group’s monthly consumption and variable revenue would not be weather normalized, and therefore the rate group will be excluded from the weather deferral account and Rider W calculations.

The AUC was satisfied with ATCO’s explanation that the usage requirements of customers under the ATA rate class would not be temperature sensitive and approved the proposal to exclude the application of Rider W to the ATA rate. It also approved ATCO’s proposal that riders A, B, D, L, S, and T should be set equal to the approved rider value or methodology in effect for the Low-Use Rate group from which the ATA rate is built. As requested by ATCO and as there would be no impact to other rate groups, the AUC approved an effective date of April 1, 2021, on a pilot basis, for the ATA rate.

Producer Receipt Rate Group

In Direction 6, the AUC required that ATCO provide a detailed analysis of the Producer Receipt Rate, including but not limited to the uptake of customers in the rate group and costs of facilities for serving these customers.

ATCO explained that Rider P, the unaccounted-for gas (“UFG”) rider charged to producer accounts, would apply to producer volumes that are transacted off the distribution system for which UFG would not otherwise be collected. ATCO stated that it anticipates producer customers connecting to the distribution system commencing April 2021 and requested that Rider P be set equal to the currently approved UFG rate for delivery customers effective April 1, 2021. ATCO noted that Rider P would be applied only to producers exporting off of the ATCO distribution system. ATCO has requested the producer rate be effective April 1, 2021, on a pilot basis, and reflected the changes in the North and South rate schedules. ATCO confirmed that it would provide the analysis on the number of customers that have connected and the cost of connecting them in the 2023 PBR rates application and the next Phase II application, as directed.

The AUC approved the proposal that Rider P is set equal to the approved UFG rate for delivery customers. The AUC also agreed with the proposal to apply for Rider P through a joint application with Rider D in August 2021. The AUC approved the producer rate on a pilot basis, effective April 1, 2021. As proposed by ATCO, the AUC further approved the inclusion of the amended Sample Producer Service Agreement and Appendix 1 as Schedule A of the producer terms and conditions as a template for contract terms.

Irrigation Fixed Charge Administration Change

In Decision 25428-D01-2020, the AUC approved a change to the administration of the fixed charge to eliminate the need for the annual seasonal process of turning the connection on and off for customers in the irrigation rate group. As a result, the fixed charge is charged seasonally by pre-set dates for the main irrigation pumping season. ATCO requested that this change be effective April 1, 2021, and approved as a change to its current interim rates.

ATCO provided calculations for the requested change and reflected this change in the South rate schedule, which outlines that a fixed charge of $1.325/day would be applied from May 1 to September 30, followed by a charge of $0 applied for the remainder of the year.

The AUC approved ATCO’s request to implement the irrigation fixed charge administration change effective April 1, 2021, as it would eliminate the need for the annual fall meter turn-off for customers, starting in 2021. The AUC approved the fixed charge from May 1 to September 30 that is based on the 2020 PBR rates, given that ATCO is currently under interim rates approved in Decision 26170-D01-2020.

Ultra-High Use Rate Group

The AUC approved the division of the High Use Rate group into the High-Use Rate group and the Ultra-High-Use Rate groups. ATCO requested approval to delay the implementation of rates for these groups to the 2022 annual PBR rate adjustment application. ATCO explained that it would file cost of service study ("COSS") updates and review and update the Rider T calculations for all rate groups as part of that application.

The AUC approved ATCO's proposal to implement the rates for the new Ultra-High-Use Rate group as part of its 2022 annual PBR rate adjustment application. Implementing these rates earlier would require a change to the COSS and Rider T methodology, which would cause mid-year rate changes for end-use customers.

Implementation and Effective Date of Restructured Rates

The Utilities Consumer Advocate ("UCA") had submitted that ATCO failed to provide enough evidence to demonstrate why implementation of rates arising from Decision 25428-D01-2020 and the present proceeding could not take place prior to January 1, 2022. The AUC found the effective rate implementation date of January 1, 2022, to be reasonable.

***ATCO Pipelines 2021-2023 General Rate Application,* AUC Decision 25663-D01-2021**
Rates - GRA

This decision provides the AUC's determinations on the general rate application ("GRA") filed by ATCO Pipelines ("ATCO Pipelines") for the 2021-2023 test years.

Rate Base

The following table set out ATCO's historical and forecast rate base:

	2019 Actual	2020 Estimate	2021 Forecast	2022 Forecast	2023 Forecast
	($000)				
Rate Base	1,827,939	2,019,761	2,213,417	2,294,651	2,328,078

Capital Expenditures

Urban Line Replacement and Pembina-Keephills Transmission Line Project

The AUC approved ATCO Pipelines' forecast capital expenditures for the Urban Pipeline Replacement ("UPR") program in the 2021-2023 test period, as filed.

In earlier decisions, the AUC had denied UPR program assets that were proposed to be transferred from ATCO Pipelines to ATCO Gas for capital tracker recovery in 2017. ATCO requested to reflect the transfer of these assets back to it in the compliance filing to this decision, where assets will be retired in the normal course of business. The AUC found insufficient information to demonstrate that ATCO has adjusted for the transfer or retirement of its UPR assets in its closing 2020 rate base. ATCO Pipelines was directed to file updated schedules showing the treatment of the asset transfers and retirements from its rate base, the corresponding associated revenue requirement impacts, and the removal of the asset transfers or retirements from its closing 2020 rate base in the compliance filing to this decision. ATCO Pipelines was also directed to provide a detailed list of any future asset transfers of this nature in future proceedings.

The Pembina-Keephills Transmission Pipeline project had been approved by the AUC in Decision 23799-D01-2019 and was to be put into service in 2020. The capital expenditures for this project were approved as filed.

General Growth Capital Expenditures Forecast

ATCO Pipelines forecast general growth capital expenditures, which included the Stoney Transmission and Calgary Stoney and Nose Creek Gates projects (collectively the "Stoney Project"). The AUC found that the Stoney Project does not meet ATCO Pipelines' threshold of $15 million for use in the three-year rolling average. ATCO Pipelines was directed to revise its revenue requirement and capital expenditure forecasts in its compliance filing to this decision to reflect the removal of the Stoney Project from the three-year rolling average in the general growth category.

ATCO Pipelines' Assets and the Integration Agreement

An Integration Agreement between ATCO Pipelines and NGTL was approved by the AUC in Decision 2010-228. This Integration Agreement specifies that ATCO Pipelines is to apply to the AUC for its revenue requirement, which, when approved, would flow through NGTL's rates. An intervener sought to confirm that ATCO Pipelines is complying with the Integration Agreement and that all of its assets in rate base are "used and useful."

The AUC accepted ATCO Pipelines' explanation that it has not been necessary to remove any assets from the rate base in the last three years and that ATCO conducts its asset review independently of NGTL, except for contracts regarding service of certain assets.

In-Line Inspection Program

The AUC found that the updated forecast capital expenditures related to the In-Line Inspection ("ILI") Program were not supported by the evidence submitted. The updated forecasts for inclusion in the improvement and replacement capital expenditures for the 2021 to 2023 test period were denied.

Weld Assessment and Repair Program

The AUC was concerned that increases in average excavation costs from $37,000 to $55,000 caused significantly increased capital expenditures: from $36,809,000 to $56,277,000 in weld inspection costs. ATCO Pipelines was directed to revise its 2021-2023 weld inspection forecast by calculating the average excavation costs per site using the actual data from projects completed from the initiation of the program in 2016 to the end of 2020 in its compliance filing. The AUC accepted ATCO Pipelines' justification of the change in program costs for repairs from $28,979,000 to $15,783,000, being the result of fewer welds needing repair. The forecast capital expenditures for weld repairs were approved as filed.

Pipeline Facilities Security Program

ATCO Pipelines proposed to initiate a multi-year program to install security enhancements into its transmission system for 100 Level 2 sites deemed as needing "high security measures" over a five-year period concluding in 2025. The AUC found evidence in support of the capital expenditures for increased security measures at Level 2 sites to be insufficient and denied the Pipeline Facilities Security Program for the 2021-2023 test years.

Spruce Grove and Stony Plain Installation

The AUC was satisfied that ATCO Pipelines had sufficiently explained the need for this project and the expenditures to ensure pipeline integrity. The forecast costs of $11.464 million were approved as filed.

General Improvements and Replacements

General improvement and replacement capital expenditures were forecast using a three-year rolling average of actual data from 2017 to 2020. The AUC found that the use of a three-year rolling average of actual data to forecast general improvement and replacement costs is representative of ATCO Pipelines' costs for these projects. The applied method to forecast general improvement and replacement capital expenditures costs were approved.

Construction Work in Progress

The AUC noted that construction work in progress ("CWIP") schedules are provided in GTAs for electric utilities. It directed that ATCO Pipelines provide these schedules on a go-forward basis in each GRA.

<u>Operating Costs</u>

ATCO Pipelines filed for approval of its total operating costs of $73,527,000 in 2021, $76,066,000 in 2022 and $77,893,000 in 2020, representing approximately 23 per cent of ATCO Pipelines' forecast total revenue requirements.

Forecasting Accuracy

Issues regarding forecasting accuracy were raised, suggesting that ATCO Pipelines had demonstrated upward bias in its forecasting approaches, resulting in excessive returns on equity ("ROEs") and that operating costs were too high, exceeding the actual costs.

While a trend analysis had been rejected by the AUC in the past, it noted that in this case, the trend analysis showed a consistent pattern of conservative forecasting by ATCO Pipelines, with the result being that the accuracy of ATCO' Pipelines forecast not having been reflective of its costs for previous periods. ATCO Pipelines was directed to, in the compliance filing to this decision, incorporate and provide an overall reduction to forecast operating costs of five per cent in each of 2021, 2022, and 2023.

Salary Escalators

The AUC found that a 1.6 per cent increase for in-scope employees, which is the bottom of the average escalator range from 2017 to 2021, is likely more representative of forecast salary escalators for the test period given the current economic conditions. ATCO Pipelines was directed to revise its out-of-scope employee salary escalator to 0.8 per cent, as the AUC determined this to be more reflective of the market and show the impacts to revenue requirements in its compliance filing.

Vacancy Rate

The AUC approved the forecast vacancy rate of 3.9 per cent for O&M and 3.3 per cent for capital for each of 2021, 2022, and 2023. ATCO Pipelines was directed to revise its forecast vacancy rates and show the impacts to revenue requirements in its compliance filing.

Pressure Vessel Inspection Compliance Program Costs

The request for an additional $828,000 in forecast cost to finalize the program in 2022 was denied, and ATCO Pipelines was directed to remove the corresponding forecast costs of $753,000 in 2021 and $75,000 in 2022 from its revenue requirements.

Pandemic Costs

The AUC directed that ATCO Pipelines established a deferral account to include a total of $2.3 million in forecast pandemic expenses over the test period.

Mid-Term Incentive Program

The AUC denied ATCO Pipelines' 2021-2023 forecast mid-term incentive program costs of $339,000 for the test period.

IT Costs

The AUC found that ATCO Pipelines should develop a long-range plan for its IT spending and provide documentation that its IT spending, capital, and O&M are consistent with those of relevant comparators. ATCO Pipelines was directed to provide its long-term IT plan and detailed IT business cases in the next GRA.

Property Taxes

The AUC directed ATCO Pipelines to establish a deferral account for forecast property tax expenses over the test period to adjust for historical property tax forecasting inaccuracies. ATCO Pipelines was also directed to reduce its property tax forecast for the 2021-2023 test years by 10 per cent, which is approximately the midpoint of the range by which property taxes have been over-forecasted from 2015-2019.

Common Issues for Proceeding 25663 and Proceeding 24964

In the absence of convincing evidence supporting a change, the AUC found a continuation of the currently approved lease rate of $20 per square foot reasonable for each of 2021, 2022, and 2023 for ATCO Pipelines.

With regard to shared services, 14 functional groups were transitioned to the shared services model. The innovation and Indigenous, government relations and sustainability ("IGRS") groups were identified as discreet functional groups for the first time in proceedings 25663 and 24964.

The AUC recognized the importance of the Indigenous relations component of the IGRS function, such as increasing focus and awareness, educational programs and training, and more. The AUC also recognized (subject to comments below) the government relations' group efforts in providing support and guidance to ATCO Pipelines and ATCO Electric on strategic government initiatives and plans, and it considers innovation to be a legitimate activity for regulated utilities.

The AUC found that the general cost allocator ("GCA") method was the most appropriate allocation method for the supply chain, financial services (not including accounts payable), regulatory, project management, innovation, and IGRS functions. While the AUC approved the use of the GCA, it noted that the evidence presented in support of the GCA had limitations. Because of these limitations, the AUC determined that there was a need for further testing to confirm the reasonableness and accuracy of the GCA allocation methodology and to ensure the reasonableness of the associated GCA allocation methodology as between regulated and non-regulated entities. The results of such testing will be filed in the next GTA / GRA ATCO Electric and ATCO Pipelines.

The AUC determined that insufficient evidence was submitted to support the forecast shared services FTE increases throughout 2020-2023. Except for the innovation function, the AUC directed ATCO Electric and ATCO Pipelines, in their respective compliance filings, to use 2019 actual FTEs as the approved total pre-allocated shared services FTE complement for all GTA and GRA test years and to then allocate these total pre-allocated shared services FTE complements in accordance with the allocators approved above. The innovation function was created in 2020. Therefore, 2019 data is not available, and ATCO Electric and ATCO Pipelines were directed to use 2020 forecast FTEs as of the approved total pre-allocated FTE component for all GTA and GRA test years.

The AUC was concerned with the number of FTEs allocated to ATCO Electric and ATCO Pipelines for services provided by the government relations and sustainability groups, as the AUC found that the inclusion of these two regulated rates provides limited benefits to the utilities and their regulated customers. Accordingly, the AUC directed ATCO Electric and ATCO Pipelines, in their respective compliance filings, to further reduce the total pre-allocated pool of IGRS FTEs by four FTEs, resulting in 11 total pre-allocation FTEs for the IGRS function for each GTA and GRA test year.

<u>Return on Rate Base</u>

In Decision 24110-D01-2020, the AUC approved the return on equity ("ROE") of 8.5 per cent and deemed an equity ratio of 37 per cent for 2021 on a final basis. ATCO Pipelines' proposed placeholder treatment of ROE and its deemed equity ratio was reasonable, pending a determination of generic cost of capital matters in future proceedings.

Debt

ATCO Pipelines was directed to revise its 2021-2023 forecast debt rate to mirror CU Inc's September 2020 debenture rate of 2.609 per cent.

Preferred Shares

The AUC found that ATCO Pipelines' preferred share forecast for the 2021-2023 test years was reasonable, with the exception of ATCO Pipelines' Series V dividend rate. ATCO Pipelines is directed to revise its Series V dividend rate to 4.6 per cent for the 2021-2023 test period.

Large Asset Purchases Deferral Account

The AUC was not persuaded that a deferral account was required for large asset purchases. In the previous ten years, there had been no large asset purchases that ATCO Pipelines was unable to forecast at the time prior to GRAs that met the proposed criteria for the large asset purchases deferral account. The only example of a project that supported the creation of a deferral account is the Pioneer Pipeline application considered in Proceeding 25937. ATCO Pipelines' request for a large asset purchases deferral account was denied, and a zero-dollar placeholder was approved pending AUC determination of the facilities application related to the acquisition of the Pioneer Pipeline.

Capital Power Generation Services Inc., Genesee Generating Station Units 1 and 2 Repowering Project, **AUC Decision 26204-D01-2021**
Facilities - Gas

In this decision, the AUC approved the application by Capital Power Generation Services Inc. to alter units 1 and 2 of the Genesee Generating Station (the "Station")

Application

Capital Power Generation Services Inc. filed an application with the AUC to alter units 1 and 2 of the Station by converting them from dual-fuel to natural gas combined cycle and to increase the total generation capability of the units from 430 megawatts to 732 megawatts. Pursuant to Approval 15623-D02-2020, Capital Power GP Holdings Inc. is the owner, and Capital Power Generation Services Inc. is the operator (collectively "Capital Power").

Capital Power stated that it would use the existing steam turbine generators and install new gas-fired combustion turbines and heat recovery steam generators and that the alteration would be done in stages to minimize downtime. During the alterations, units 1 and 2 would operate in simple-cycle. The in-service date for unit 1 is expected to be September 2023 for the simple-cycle and December 31, 2023, for the combined cycle, and the in-service date for unit 2 is expected to be December 2023 for the simple-cycle and March 31, 2024, for the combined cycle. Construction activities are planned to begin as early as July 2021. Following the alteration, units 1 and 2 would no longer require the boilers and coal-fired equipment, and that equipment would be decommissioned.

The AUC issued a notice of application, and no submissions were received in response.

Findings

The AUC found that approval of this project is in the public interest, including its effect on the environment. It determined that the information requirements specified in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations, and Hydro Developments* were met and that no submissions were received in response to the notice of application.

The simple-cycle operation of the project will last approximately ten months and will therefore not be considered a construction activity or temporary noise-generating activity in the context of Rule 012. Based on noise prediction results submitted by Capital Power, the AUC found that both simple-cycle and the combined operation will be compliant with Rule 012.

The AUC acknowledged that Capital Power has filed an application with Alberta Environment and Parks ("AEP") for an amendment to its *Environmental Protection and Enhancement Act* approval and that AEP will consider the air quality assessment in its independent evaluation.

<u>Conclusion</u>

Pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act*, the AUC approved the application to alter and operate the Station.

***Capital Power Generation Services, Whitla Phase 3 Wind Power Plant,* AUC Decision 25909-D01-2021**
Facilities - Wind Power

In this decision, the AUC approved the application from Capital Power Generation Services Inc. ("Capital Power") to construct and operate the Whitla Phase 3 Wind Power Plant (the "Power Plant").

<u>Application</u>

Capital Power had been granted permission to construct and operate the Whitla Phase 2 Wind Power Pant in Approval 25780-D02-2020. Capital Power applied to amend approval 25780-D02-2020 by adding the 54-megawatt ("MW") power plant to the Whitla Wind Project (the "Project").

The Power Plant would consist of 15 Vesta V126 – 3.6-MW turbines, which is the same turbine that was approved for the Whilta Phase 1 Power Plant and the Whitla Phase 2 Power Plant. Power generated by the wind turbines would be connected to the Alberta Interconnected Electrical System ("AIES") via AltaLink Management Ltd.'s 240-kilovolt transmission system. The Project would not require any new transmission infrastructure. An amendment to the existing connection order was not required.

Capital Power submitted an environmental evaluation report ("EEP"), a renewable energy report ("RER") provided by Alberta Environment and Parks ("AEP"), a shadow flicker assessment, a noise impact assessment, a participant involvement program, and confirmation that *Historical Resources Act* approval had been received

<u>AUC Findings</u>

The AUC considered this application under sections 11 and 19 of the *Hydro and Electric Energy Act* (*"HEEA"*). In accordance with Section 17 of the *Alberta Utilities Commission Act* (*"AUC Act"*), the AUC considered whether the Project was in the public interest.

The AUC found that the approval of the Project would be in the public interest. In finding this, the AUC considered the social, economic, environmental, and other effects of the Project.

The AUC determined that the information requirements Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* had been met. The AUC also found that the participant involvement program satisfied the requirements of Rule 007.

The AUC noted that the Project had been sited to avoid certain wildlife features of concern. Alberta Environment and Parks ("AEP") determined that the overall project risk would be moderate based on high wildlife use within the project areas, particularly bats and avian species at risk. The AUC determined that siting the Project entirely on cultivated land and outside of the setback of the Forty Mile Coulee would reduce the impacts to wildlife and wildlife habitat in the Project area.

In its referral report, AEP identified that preliminary raw mortality data from operational wind projects in the area suggested that bat mortality would be high. As a result, AEP anticipated that future operational mitigation would likely be required for the Project. AEP also found that the Project's bat mortality risk during operation would be high based on survey results, but the risk could be reduced to moderate if Capital Power would commit to pre-emptive operational mitigation measures as described in the referral report.

At the time this decision was issued, Capital Power did not commit to implementing pre-emptive operational mitigation measures. Capital Power did commit to meet with AEP to discuss the results of the first year of the post-construction mortality monitoring program for Whitla Phase 1 Wind Power Plant. It noted that it would be in a better position to assess the merits of implementing pre-emptive operational mitigation at that time. The AUC agreed with this submission and, as a result, included the following condition:

> a) Capital Power shall submit a summary of the results of the discussion held with Alberta Environment and Parks, including a description of any pre-emptive operational mitigation measures that Capital Power has agreed to implement. If new mitigation measures were agreed to, Capital Power must submit an updated construction and operation mitigation plan that incorporates the additional mitigation measures at least 60 days prior to the start of construction of the Whitla Phase 3 Wind Power Plant turbines.

The AUC further noted that Capital Power was required to comply with the requirements of Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants*. Subsection 3(3) of Rule 033 requires the approval holder to submit to AEP and the AUC annual post-construction monitoring survey reports. As a result, the AUC imposed the condition that Capital Power shall submit an annual post-construction monitoring survey report to AEP and the AUC for all three phases of the Whitla Wind Project.

The AUC found that Capital Power's construction monitoring plan would adequately address potential environmental impacts of the Project. The AUC also found that the discussion with AEP and the implementation of additional mitigation measures directed by AEP would ensure that the Power Plant would align with AEP's post-construction wildlife requirements.

The AUC found that with diligent application of all the discussed mitigation measures, the potential adverse environmental effects of the Project, including those on wildlife and wildlife habitat, could be adequately mitigated.

Capital Power submitted a noise impact assessment ("NIA") that predicted that the proposed Project would comply with Rule 012: *Noise Control*. The AUC noted that the noise study area for the Project contained a significant number of energy-related facilities that potentially influence cumulative sound levels at affected receptors. The Commission found that Capital Power reasonably identified baseline facilities with the potential to influence cumulative sound levels at affected receptors and established reasonable sound power levels to calculate the contribution of baseline facilities to cumulative sound levels at affected receptors.

However, because the predicted cumulative sound levels at five receptors exceed the 40 dBA nighttime PSL and because of the small margin of compliance at ten other receptors, the AUC found that the Project's compliance with Rule 012 required additional scrutiny. Accordingly, as a condition of approval for the Project, the AUC required Capital Power to conduct a post-construction comprehensive sound level ("CSL") survey to confirm compliance with Rule 012. Receptors R13 and R26 had been identified as the receptors at which the Project would be a major noise contributor. Accordingly, the post-construction CSL survey was required to include an evaluation of low-frequency noise at receptors R13 and R26.

The AUC reviewed conditions of approval in Approval 25780-D02-2020 for the Whitla Phase 1 Wind Power Plant and Whitla Phase 2 Wind Power Plant and updated them as necessary to include matters relating to the Whitla Phase 3 Wind Power Plant.

The AUC noted that, at the time of the application for this decision, there were no public safety standards or regulations associated with shadow flicker. The AUC accepted Stantec Consulting Ltd.'s conclusion that no residence would be affected by more than 30 hours per year or more than 30 minutes per day of shadow flicker. The AUC was satisfied that the shadow flicker effects would be minimal.

The AUC considered approval of the application to be in the public interest. Subjected to the noted conditions, the AUC approved the application.

***Concord Monarch GP2 Ltd. Monarch Solar Project Amendment*, AUC Decision 26362-D01-2021**
Solar - *Facilities*

In this decision, the AUC approved the application from Concord Monarch GP2 Ltd. ("Concord") to amend its power plant approval and finalize its generation equipment for the Monarch Solar Project.

In Decision 25711-D02-2020, Concord had been granted approval to construct and operate the Monarch Solar Project Power Plant. Concord applied to reduce the land required for the power plant. Concord further submitted its final selection of generation equipment.

The AUC found that the amendments and the application met the requirements of Sections 11 and 12 of the *Hydro and Electric Energy Regulation.*

The AUC accepted the results of the solar glare assessment submitted by Concord, which indicated that the project amendments would decrease or eliminate glare at all transportation routes and all dwellings, except two dwellings, and that the glare increases at these two dwellings would be small. The AUC accepted the overall conclusion of the solar glare assessment that the project is unlikely to create hazardous glare conditions for nearby dwellings or transportation routes.

Pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act*, the AUC approved the application from Concord Monarch GP2 Ltd.

***Concord Vulcan GP2 Ltd. Vulcan Solar Project Amendment,* AUC Decision 26349-D01-2021**
Facilities - Solar Plant - Capability Decrease

In this decision, the AUC approved the application from Concord Vulcan G2 Ltd. ("Concord") to amend its power plant approval and finalize its generation equipment for the Vulcan Solar Project.

<u>Background</u>

In Decision 26172-D02-2020, Concord had been granted approval to construct and operate the Vulcan Solar Project Power Plant. Concord applied to decrease the power plant capability from 25 megawatts to 22 megawatts. Concord also submitted its selection of generation equipment.

An updated solar glare assessment for the project was conducted, and the glare predictions were compared with the glare assessment submitted for the original application. It concluded that proposed amendments to the project would decrease or eliminate yellow glare for most of the previously assessed receptors. However, yellow glare was expected to increase to up to 2,823 minutes per year, compared to zero in the original application, for the receptor at Range Road 243. However, vehicle operators using the impacted transportation routes would experience only a fraction of the predicted glare as they would travel past the project site and do not stand still while looking at the project solar arrays. Further, an existing shelterbelt along the western side of the project would partially mitigate glare effects on Range Road 243. The solar glare assessment concluded the project would be unlikely to create hazardous glare conditions for nearby dwellings, transportation routes, or heliport.

<u>AUC Findings</u>

The AUC found that Concord demonstrated that the requested amendments met the requirements of Sections 11 and 12 of the *Hydro and Electric Energy Regulation.*

The AUC accepted the conclusion of the solar glare assessment that the project is unlikely to create hazardous glare conditions for nearby dwellings, transportation routes, or heliport. The AUC noted its expectation that any glare issues associated with the project would be addressed by Concord in a timely manner and added conditions to reflect that expectation. Subject to those conditions, and pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act*, the AUC approved the application from Concord Vulcan GP2 Ltd.

***ENMAX Corporation Code of Conduct Regulation Compliance Plan Amendments,* AUC Decision 26295-D01-2021**
Code of Conduct Compliance Plan

In this decision, the AUC approved the application from ENMAX Corporation ("ENMAX") for approval of its *Code of Conduct Regulation* ("*CCR*") Compliance Plan, with the inclusion of provisions directed by the AUC.

Background

The *CCR* was amended, effective November 12, 2020, to remove or update various required sections from utilities' *CCR* compliance plans.

Pursuant to Subsection 32(2) of the *CCR*, ENMAX requested approval of changes to its compliance plan to reflect the removal and amendments to the sections. ENMAX has also made some minor administrative changes.

AUC Findings

The AUC was satisfied that the removal of the affected sections and other administrative amendments made by ENMAX were consistent with continued compliance with the *CCR*. It also noted that the changes sufficiently addressed the requirements of the *CCR*.

The AUC was concerned that the compliance plan contained no provision for the creation and retention of the records required for the AUC to carry out its future audits, as required under Section 40 of the *CCR*. Therefore, it directed ENMAX to include a specific text under 'DIVISION 3 COMPLIANCE AUDIT' in its *CCR* Compliance Plan that would ensure that ENMAX Power Corporation and ENMAX Energy Corporation would retain the necessary records and accounts.

The AUC directed that ENMAX file the revised compliance plan, including this addition, no later than April 7, 2021. The AUC approved the ENMAX Corporation *CCR* Compliance Plan with the changes directed by the AUC.

***ENMAX Power Corporation Southeast Substation Transmission Line Development Project,* AUC Decision 25934-D01-2021**
Facilities - Salvage

In this decision, the AUC denied applications from ENMAX Power Corporation ("EPC") to salvage equipment from the ENMAX No. 32 Substation (the "Substation") and to replace that equipment at another substation.

Introduction and Background

EPC explained that the Substation flooded in June 2013 and stated that the City of Calgary's Land-Use Bylaw (the "Bylaw") prevents the construction or expansion of buildings within floodways. EPC identified an arc flash hazard from the outdoor switchgear at the Substation that poses a safety concern to employees at the Substation.

EPC applied to the AUC to salvage equipment from the Substation and to replace that equipment at either a new substation, designated as ENMAX No. 45 Substation, or at the existing ENMAX No. 31 Substation. The applications were registered on October 9, 2020, as applications 25934-A001 to 25934-A004.

Discussion

EPC proposed two alternatives to replace the salvaged substation equipment. The preferred alternative was to construct a new substation, ENMAX No. 45 Substation, in the community of Shepard Industrial near Quarry Park and to connect that substation to existing Transmission Line 138-31.84L by constructing approximately 800 meters of double-circuit 138-kilovolt ("kV") transmission line. The cost of this alternative was estimated to be $62.6 million. In the second alternative, EPC proposed to expand the existing ENMAX No. 31 Substation for an estimated cost of $68.2 million.

Based on similar projects, EPC estimated the cost of the new switchgear, a new structure to house the switchgear, and other associated costs to be approximately $8.5 million. It did not provide a detailed cost estimate for replacing the switchgear on-site at the Substation.

EPC further submitted that it would likely pursue decommissioning the Substation in the long term. It provided cumulative present value calculations of its preferred option, inclusive of the flood mitigation and the eventual salvage costs, and for decommissioning the entirety of the Substation now. ENMAX assumed that for its preferred option, the remainder of the Substation would be salvaged in 2058 and calculated the cumulative present value of the revenue requirement to be approximately $64.8 million. It calculated the cumulative present value to decommission and relocate the entire Substation now to be approximately $79.6 million.

Findings

The AUC found that EPC did not provide enough evidence to demonstrate that either option was in the public interest.

The AUC recognized that a safety issue exists at the Substation and that equipment needs to be salvaged and replaced at some point in time to eliminate the identified hazard. Further, while the AUC understood EPC's reluctance to install new equipment at a substation within a floodway, it had issues with that position when EPC proposed to install further flood mitigation and plans to leave equipment at the Substation. It noted that EPC had upgraded this substation in 2012-2013 while aware of the flood risk. The AUC questioned the need to spend significant capital to relocate substation equipment to an alternate site at the time of this proceeding.

The AUC clarified that the safety issue related to arc flashing could be solved by new switchgear moved to an indoor location, and at the existing site, this would cost approximately $8.5 million. The AUC was not satisfied that EPC has adequately explored options to install the equipment on-site to resolve the safety issue, which, according to EPC's estimates, would cost approximately $55 million less to ratepayers than any other options it applied for.

EPC commented on the Bylaw, submitting that it restricts its ability to construct or expand a building at the existing site. However, EPC stated that it could not speculate on how the City of Calgary would view the prohibition on expanding the footprint of the existing building. It also indicated that transmission lines and substations might be exempt from Part 17 of the *Municipal Government Act,* under which the Bylaw is enacted. The AUC found that, because EPC relied on the Bylaw restrictions to justify its alternative, it should have taken steps to confirm if the Bylaw applies. The AUC expected EPC to submit documentation of its discussion with the City of Calgary on this matter, which could have clarified the City of Calgary's understanding of the applicability of the Bylaw.

The AUC considered EPC's statement that it would not be prudent to make a major investment in a substation that is located in a floodway and that was completely isolated by water during the 2013 flood. But it did not believe that $8.5 million to resolve a safety risk on-site constitutes a major investment in these circumstances. Because the alternatives presented by EPC are approximately $55 million more expensive, a more thorough investigation into what is in the public interest is required. Further, EPC's statement did not adequately consider the mitigations it implemented in 2012 and 2013 and since the 2013 flood or the mitigations it is proposing to make in the future. Nor does it consider any additional upstream mitigations that have been implemented or that are being considered that would help to mitigate flood risk at the Substation. The AUC noted that EPC was aware of the flood risks to the Substation when it applied for upgrades in 2011 but considered that upgrading the Substation at the existing location was the preferred option while indicating that it would investigate mitigation measures to protect substation equipment from the high-water levels of a flood.

The AUC denied the applications.

NEXUS Energy Associates Ltd. Rocky Power Plant and Interconnection, **AUC Decision 26191-D01-2021**
Facilities - Gas

In this decision, the AUC approved the applications filed by NEXUS Energy and Associated Ltd. ("NEXUS") to construct and operate a power plant designated as the Rocky Power Plant (the "Power Plant"), located in the Rocky Mountain House Area, and to connect the Power Plant to the Alberta Interconnected Electric System ("AIES"), collectively the "Project".

The Project is located adjacent to the existing Obsidian Gas Plant. The Power Plant would consist of four one-megawatt natural gas-fired generators. Installation of a dedicated natural gas pipeline running from the Obsidian Gas Plant to the proposed Power Plant would be required. The Power Plant would also connect to FortisAlberta Inc.'s existing 25-kilovolt distribution line.

NEXUS had retained RWDI AIR Inc. ("RWDI") to conduct an air quality assessment for the Project. The dispersion modeling results showed that predicted concentrations for most substances of interest and averaging periods were less than the limits set by the *Alberta Ambient Air Quality Objectives*. However, the predicted cumulative concentration for nitrogen dioxide, which included external sources and background, exceeded at a few receptors. These exceedances occurred at receptors located within the fenceline of external industrial property. RWDI submitted that the exceedances were due to the external sources exceeding at the nearby receptors, whereas the proposed project does not contribute significantly to the concentration at those receptors. RWDI concluded that the Project would not contribute materially to the overall predicted air contaminant concentrations in the study area.

<u>AUC Findings</u>

The AUC reviewed the applications and found that the technical, siting, noise, and environmental information requirements specified in Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* had been met. It also noted that the participant involvement program conducted by NEXUS had met the requirements of Rule 007 and noted that no submissions were received in response to the notice of applications.

The AUC acknowledged that NEXUS had filed an application with Alberta Environment and Parks ("AEP") for *Environmental Protection and Enhancement Act* approval. AEP will consider the air quality assessment in its independent evaluation. The AUC also noted that, although the air quality assessment predicted exceedances of *Alberta Ambient Air Quality Objectives* in the cumulative case of nitrogen dioxide, these exceedances were determined to be caused by existing external sources. The AUC accepted RWDI's conclusion that the Project would not contribute materially to the predicted exceedances at those external receptors and would not significantly impact the air quality in the study area. As the predicted concentrations for most substances of interest and averaging periods were less than the applicable limits; that the proposed Project does not cause the cumulative exceedance for nitrogen dioxide; and, that no exceedances of the *Alberta Ambient Air Quality Objectives* for nitrogen dioxide are predicted outside the fence line of the existing industrial facilities, the AUC found that the environmental impacts of the Project are not significant.

The AUC considered the Project to be in the public interest and, pursuant to sections 11 and 18 of the *Hydro and Electric Energy Act*, approved the applications.

Three Nations Energy GP Inc. Fort Chipewyan Solar Generation Facility (Phase 2) Amendment, AUC Decision 26347-D01-2021

Facilities - Solar Plant

In this decision, the AUC approved an application from Three Nations Energy GP Inc. ("Three Nations") for the alteration of a power plant designated as the Fort Chipewyan Solar Generation Facility (Phase 2).

Discussion

The Fort Chipewyan Solar Generation Facility (Phase 2) was completed and energized in January 2021. Three Nations recently determined that there was enough room in the project budget to purchase and install an additional 384 solar panels, which would add approximately 154 kilowatts of additional generation capability to the existing 2.27-megawatt power plant.

ATCO Infrastructure Services with the support of ATCO Electric Ltd. planned to start construction in March 2021 and expected an in-service date of August 31, 2021, for the alteration.

AUC Findings

The AUC reviewed the application and determined that the technical, siting, environmental, and noise aspects of the power plant alteration were met. Three Nations' participant involvement program was conducted, and there were no outstanding public or industry objections or concerns.

Based on the minor nature of the proposed alteration, it was the AUC's understanding that the proposed changes do not constitute "changes that may make the community generating unit cease to be a community generating unit" within the meaning of Section 10(1) of the *Small Scale Generation Regulation*. It noted that nothing in this decision should be construed as approving any changes to the terms under which the project was qualified as a community generating unit. Accordingly, the AUC imposed the following condition of approval:

> Within 30 days of the issuance of this approval, Three Nations shall confirm with the AUC whether the alteration will result in changes to ATCO's assessment of whether the power plant qualifies as a small-scale generating unit; the community benefits agreement; the status of the community group named in the community benefits agreement; the benefits received by the community group under the community benefits agreement; or the metering costs for the project.

Decision

Pursuant to sections 11 and 19 of the *Hydro and Electric Energy Act*, the AUC approved the application and granted Three Nations approval to alter and operate the Fort Chipewyan Solar Generation Facility (Phase 2).

***Tomahawk REA Ltd. Varied Code of Conduct Regulation Compliance Plan Amendments,* AUC Decision 26235-D01-2021**

Code of Conduct Compliance

In this decision, the AUC approved the application from Tomahawk REA Ltd. ("Tomahawk") to amend its varied code of conduct compliance plan.

Background

Tomahawk filed its application pursuant to the *Code of Conduct Regulation* ("*CCR*") and Rule 030: *Compliance with Code of Conduct Regulation*. Subsection 37(1)(a) of the *CCR* authorizes the AUC to make a rule to vary the requirements of Subsection 30(4) "in the case of a distributor with a small number of customers…".

Subsection 3(1) of Rule 030 came into effect on April 1, 2016. Subsection 3(1) of Rule 030 provides that a distributor with fewer than 5,000 customers may file a varied compliance plan. Tomahawk's submission of a varied compliance plan was approved in Decision 21657-D01-2016.

In this application, Tomahawk submitted that it had signed a distribution system operator and regulated rate option agreement with Battle River Power Co-op, effective January 5, 2021. Tomahawk has also changed its compliance officer.

AUC Findings

The AUC found that the changes made to Tomahawk's varied compliance plan are consistent with continued compliance with and sufficiently address the requirements of *the Code of Conduct Regulation* and Rule 030.

University of Calgary Application for a Duplication Avoidance Tariff – Stage 1, **AUC Decision 25826-D01-2021**

Tariff - Electricity

In this decision, the AUC denied the application from the University of Calgary ("U of C") to receive a duplication avoidance tariff ("DAT") from ENMAX Power Corporation ("EPC").

Procedural Summary

The U of C explained that its first stage application would address whether a bypass avoidance rate was required to respond to a bypass threat. The AUC accepted the staged approach proposed by the U of C to prevent the need for EPC to prepare an application if this Stage 1 application did not advance further. The AUC ruled that the focus of the first stage application was to test the credibility of the threat of bypass.

Background

DATs have generally been granted in response to an end-user customer's ability and threat to construct its own facilities to bypass the existing system to reduce its regulated utility charges. These facilities could cause harm to the regulated utility, and to its other customers, by reducing the regulated utility's revenues without an equivalent decrease to its costs.

In considering DAT applications, the predecessor of the AUC, the Alberta Energy and Utilities Board ("the Board"), had typically considered the following criteria:

(a) The bypass avoidance rate is required to respond to a credible bypass threat;

(b) The bypass avoidance rate must exceed the long-run incremental cost of service;

(c) The bypass avoidance rate is no more attractive than is reasonably required to avoid duplicate facilities; and

(d) The cost of offering the bypass avoidance rate is appropriately shared between other utility customers and the utility shareholders.

Details of the Application

The U of C submitted a DAT application on the premise that it could construct additional facilities ("cable upgrades"). The cable upgrades would result in a greater interconnection of its main campus electrical loads. The U of C submitted that if the cable upgrade were constructed, all six connections to the EPC distribution system would be totalized under one Rate Code D600 - Large Distributed Generation Account, rather than the two currently billed under D600.

The U of C submitted that with the cable upgrades in place, four of its current connections to EPC's distribution system could become redundant and not be utilized during normal operations. These connections would be retained for use in situations where the two primary connections were unable to fully supply the main campus's electrical load.

Had the cable upgrade been in place in 2019, the U of C estimated that it would have saved $4.4 million in electric utility costs in that year. It estimated the cost to construct to be around $880,735 and the cost to maintain the cable upgrades to be approximately $500 per month. It submitted that the cable upgrade would be economical.

Discussion

The AUC noted that an applicant might be eligible to receive specialized tariff treatment in the form of a DAT in circumstances where the threat of the bypass is credible and where preventing it through a demonstration of benefits is in the public interest.

The AUC stated that the underlying inquiry at this stage of the application should focus on whether a credible bypass proposal exists, and if so, whether it poses a threat in the form of harm to other customers, such that it is in the public interest to mitigate that harm by developing a DAT. This inquiry should also assess whether the construction of facilities that do not result in the stranding of existing regulated utility assets consists of a credible bypass, and furthermore, one that poses a threat, triggering the need for specialized tariff treatment to avoid construction of the proposed facilities.

Does the U of C's Proposal Result in a Credible Bypass of Distribution Facilities?

The AUC could not conclude that the cable upgrades comprise a credible proposal to bypass the distribution system.

The U of C submitted that the cable upgrade would constitute a bypass of the distribution system. With the installation of the cable upgrades, the four connections billed under the D410 account would be retained for use as backup supply during abnormal situations. The U of C would pay a dedicated facilities' charge for these connections. The AUC noted that additional information supplied in information request responses presented a conflicting view on whether all existing regulated assets would be retained and used by the U of C.

The U of C submitted that if its load were to grow above the limit that can be supplied by the two D600 feeders, one or more of the existing D410 feeders would have to be used during normal operations, even with the cable upgrades installed. The U of C's maximum load at the time of the application was 22 megawatts, and the capacity of the two D600 feeders 26 megavolt-amperes.

The AUC found it unclear whether the proposed cable upgrade would result in the U of C being able to construct alternate facilities to meet its own electricity requirements, thereby eliminating its need for some or all the existing regulated utility facilities that previously served the customer. The AUC was not persuaded that existing primary feeders becoming backup feeders or feeders not used during normal operations eliminated the need for regulated distribution facilities to meet the U of C's electricity requirements. If substantially all the existing regulated facilities are still required to provide service to a customer, then a bypass of the interconnected electric system has not occurred. The U of C did not provide suitable evidence on this point to allow the AUC to decide that its facilities, as proposed, constitute a bypass of EPC's distribution system.

Does the Proposal Cause Harm to a Regulated Utility or to its Customers?

The U of C submitted calculations detailing how the cable upgrades would reduce the amounts it pays annually for its electric utility services, as well as how EPC's charges from the Alberta Electric System Operator ("AESO") could change if the cable upgrades were constructed.

While estimating that the cable upgrades would reduce its electric utility costs by $4.4 million annually, the U of C also estimated that the cable upgrades could increase EPC's charges from the AESO by up to $560,000 annually. The AUC could not rely on the U of C's calculations, as they contained material errors related to the calculation of its estimated savings and the calculation of the change in EPC's transmission system access service charge from the AESO. The U of C also submitted that the cable upgrades would increase its annual distribution charges, resulting in increased distribution revenue to EPC. This would be inconsistent with the purpose of granting a DAT.

As a result, the AUC could not conclusively determine how EPC's revenues and costs would be affected if the cable upgrades were constructed or if EPC's distribution customers or all customers of the transmission system in Alberta would be harmed by the construction of the cable upgrades. It was, therefore, unable to conclude that, even if it were credible, the proposed bypass would constitute a threat to EPC or its other customers.

Is There Material Benefit from the Development of a DAT?

For a DAT to be in the public interest, there must be a material benefit associated with its approval that warrants the effort that is required by all parties to develop, approve and implement the DAT. The benefits can take various forms, including the minimization of potential revenue loss to a regulated utility and the prevention of stranded assets. The U of C requested that its DAT contain a one-time payment to EPC of $880,735 and monthly payments of $500.

The AUC acknowledged that the specific terms of a DAT fall outside the scope of the Stage 1 application. The AUC did, however, not view the potential benefits from the development of a DAT to be sufficiently material in this case to warrant the advancement of the application.

The AUC denied the application from the U of C for a duplication avoidance tariff.

CANADA ENERGY REGULATOR

***The Explorers and Producers Association of Canada- Decision on Application to Extend the NOVA Gas Transmission Gas Transportation Temporary Service Protocol Tariff Provision* CER Decision File OF-Tolls-Group1-N081-2020-03 01 and Order TG-001-2021**

Review and Variance - Supply and Markets - Toll Principles

In this decision, the CER dismissed the Explorers and Producers Association of Canada ("EPAC")'s application to extend the NOVA Gas Transmission ("NGTL") Gas Transportation Temporary Service Protocol ("TSP") Tariff Provision and directed NGTL to file its progress on access to storage with the CER by 30 June 2021.

Background

EPAC filed an application with the CER to extend NGTL's Gas Transmission TSP until the earlier of 31 October 2021 or until leave to open the final component of the 2021 NGTL System Expansion Project.

The TSP was added to the NGTL tariff as a result of CER Decision RH-002-2019 re *NGTL's Application for Approval of Amendments to the NGTL Gas Transportation Tariff - Temporary Service Protocol* (November 2019) ("TSP Decision"). The TSP amended the tariff to prioritize interruptible delivery and storage injection over receipt services (interruptible or firm) to manage system constraints during planned outage/maintenance periods on the NGTL System at and upstream of Clearwater and Woodenhouse Compressor Stations.

EPAC asserted that the CER had the authority to grant the relief requested by means of a review and variance of the TSP Decision under Section 69 of the Canadian Energy Regulator Act ("*CER Act*") because of the changed circumstances affecting the timing of the 2021 NGTL System Expansion Project; or pursuant to the CER's general powers relating to all matters affecting tolls and tariffs set forth in sections 225 to 240, and specifically Section 226, of the *CER Act*. The CER was not persuaded that EPAC established that relief should be granted under either provision.

Burden of Proof

Typically, traffic tolls and tariff matters have been brought before the CER's predecessor, the National Energy Board ("NEB") either in the form of an application from a pipeline company seeking approval or in the form of a complaint from one or more shippers. The CER noted that this application was unlike either of these typical forms, with an industry group seeking to affect a continuation of a temporary amendment to a pipeline company's tariff without a complaint and in the face of opposition by the pipeline company. A consideration of the applicable burden of proof and the operation of the NEB and CER's tolling principles was warranted.

The NEB commented on the burden of proof in its reasons for decision in GH-2-87 and affirmed that the applicant has the burden of establishing, on a balance of probabilities, that the relief sought in its application should be granted. The CER was of the view that this is the case where a third party such as EPAC is seeking to compel a pipeline company (who is not the Applicant) to change or amend its tolls or tariffs.

Tolling Principles

In its reasons for the TSP Decision, the CER acknowledged previous decisions of the NEB, which articulated tolling principles that assist in the interpretation and application of statutory provisions in respect of traffic, tolls, and tariff matters. These fundamental tolling principles include cost-based / user-pay, no acquired rights, and economic efficiency.

Review and Variance:

Demonstrating on a prima facie basis sufficient grounds to raise a doubt as to the correctness of a prior decision or order is the first step of a review and variance application under Section 44 of the *National Energy Board Rules of Practice and Procedure, 1995* (the "Rules") and Section 69 of the *CER Act*. An application pursuant to

Subsection 69(1) is one to review, vary or rescind a prior decision or order. The CER noted that the relief sought by EPAC viewed through this provision of the *CER Act* is a variance of the terms of expiry of the previous order, which would result in an extension of the applicability of the TSP.

Paragraph 44(2)(b) of the Rules describes three possible grounds to raise a doubt about the correctness of the order. EPAC made clear that it was not arguing any error of law or jurisdiction in respect of the TSP Decision. Rather, EPAC asserted that the CER had made the right decision in respect of the previous application. During the final argument, EPAC stated that its request for relief should not require a re-evaluation of whether the TSP Decision was decided correctly.

Implicit in EPAC's argument in favor of a review and variance in this instance was that the delay for the in-service date of the NGTL 2021 facilities gave rise to similar conditions, which grounded the CER's decision to grant the TSP in the first instance. Namely, the delays in the in-service dates for the NGTL 2021 facilities constitute changed circumstances or new facts as contemplated by subparagraph 44(2)(b)(ii) of the Rules, arising since the close of the previous hearing. To accept this argument as a basis for the variance of the TSP's expiry would require the CER in this instance to accept that the presumed in-service date of the NGTL 2021 facilities was the basis for the establishment of the expiry date in its first decision, but the timing of the CER's order was not explicitly and singularly linked to NGTL 2021. Moreover, NGTL's submissions correctly point out that the NGTL 2021 application was still before the CER for decision at that time. Given that the potential approval, timelines, and conditions of approval for the NGTL 2021 were unknown at the time of the original 2019 TSP Application, the eventual delay in the 2021 NGTL System Expansion Project does not constitute a changed circumstance or new fact today. For these reasons, EPAC did not raise sufficient grounds so as to cast doubt on the correctness of the previous TSP ruling and Order. As a result, the CER dismissed the review request.

Regarding the CER's broad authority under Section 226 of the *CER Act*, the CER similarly found that EPAC did not establish that the CER should exercise its discretion to issue an order to NGTL to alter its tariff. The CER found that EPAC did not establish, on a balance of probabilities, that the likelihood of constraints that impact access to storage during summer 2021 is sufficiently great as to warrant the imposition of the TSP on the NGTL System. The CER considered both the facility additions pursued by NGTL following the TSP Decision and delayed construction of the 2021 NGTL System Expansion Project. The CER was persuaded that capacity additions implemented by NGTL following the TSP Decisions had reduced the acute capacity constraints that premised the 2019 approval of the TSP. As noted above, the 2021 NGTL System Expansion Project was under regulatory consideration and not yet approved at the time the TSP Decision was made. That expansion alone was not central to the TSP Decision.

The CER accepted NGTL's evidence that there are unlikely to be constraints that impact access to storage resulting from the 30 Daily Operational Plan ("DOP") outages in the TSP-applicable areas in summer 2021. NGTL's submissions regarding the scheduling and execution of planned maintenance, tie-ins, and new facilities and the probability of constraints in summer 2021 were detailed and consistent, including in response to challenges by EPAC that 2021 supply and system demands are more likely to resemble those of 2019. The DOP outages anticipated for TSP-applicable areas in summer 2021 are fewer than the 36 outages that occurred in the summer of 2019 when the TSP was needed and the same number of DOP outages that occurred in the summer of 2020 when the TSP was not needed.

The CER found that the market dynamics detailed in this proceeding also differ from those found in the TSP Decision. The market volatility experienced from 2017 to 2019 is no longer present. Since 2019, the AECO market has reconnected with Henry Hub. EPAC and supporters of the application pointed to the TSP as the main factor responsible for the market rebalancing, while NGTL and those parties opposed to the application submitted that the primary factor was facility additions on the NGTL System. Although the CER continues to view the TSP Decision as appropriate for 2019 and 2020, the CER found that there is insufficient evidence to establish the full extent to which the TSP contributed to the reconnection of AECO to Henry Hub, as compared to other factors, including facility additions. In light of the CER's findings regarding changed market conditions, and EPAC having failed to establish, on a balance of probabilities, that the TSP was primarily responsible for the market reconnect following the TSP Decision, the CER held that EPAC did not meet its burden to establish that the CER should exercise its broad statutory discretion to extend the TSP in this instance.

The CER also considered the potential merits of the TSP as an insurance policy and found there was insufficient evidence for it to draw a conclusion with respect to forecasting the potential benefits compared to its potential adverse impacts in summer 2021. The CER noted that, while the TSP was argued to be a policy to smooth price volatility market-wide, other options exist for producers to self-insure against the volatility of the spot market, such as entering into long-term sale arrangements. In the proceeding, some producers who availed themselves of those options opposed the application. The CER acknowledged that these strategies might not fully mitigate challenges associated with access to storage on the NGTL System, but that result, alone, is insufficient to establish that the CER should exercise discretion to order NGTL to amend its tariff.

<u>Order</u>

Throughout the hearing, the CER heard concerns that accessing storage on the NGTL System would continue to be a challenge, even upon completion of the 2021 NGTL System Expansion Project. The evidence demonstrated that storage plays an important role in the Western Canadian natural gas market. Ensuring access to storage is, therefore, an integral part of a well-functioning natural gas market and no party in the proceeding denied the importance of storage facilities to the NGTL System.

In the TSP Decision, the CER outlined that it expected NGTL and its customers to continue to explore alternative long-term solutions that will meet system needs, enable continued access to storage during periods when it is critical, and ultimately enhance the efficient functioning of the NGTL System thereby supporting market stability.

While NGTL made some efforts to bring about improved access to storage in summer 2021, the CER remained concerned about the pace of progress by NGTL regarding the critical issue of access to storage, including the lack of detail provided by NGTL regarding the Transfers to Storage initiative, the initial launch of a pilot almost two years after the TSP Decision and the concerns raised by some parties about NGTL's consultations with all interested parties. To ensure that the ongoing storage access issues are addressed transparently, meaningfully, and in a timely manner, the CER issued Toll Order TG-001-2021, requiring a filing from NGTL by 30 June 2021.

The CER directed that the filing may be an application if a tariff amendment is required or may make use of existing NGTL tariff provisions. Regardless of what option NGTL chooses to pursue, the filing must include:

(a) a detailed description of the methodology;

(b) an assessment of the appropriateness of the associated market signals;

(c) the extent to which the revisions will enable access to storage;

(d) whether the proposed tariff revisions will result in tolls that are just and reasonable and not unjustly discriminatory;

(e) whether the revisions will promote economic efficiency, both in the use of the existing NGTL System and signaling the need to build additional capacity; and

(f) a description of consultations undertaken with shippers and impacted parties.

Any long-term solution should adhere to the cost causation toll principle, which states that tolls should be, to the greatest extent possible, cost-based and that the users of a pipeline system should bear the financial responsibility for the costs caused by the transportation of their product through the pipeline.