REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA COURT OF APPEAL

***Normtek Radiation Services Ltd. v Alberta Environmental Appeal Board,* 2020 ABCA 456**

Meaning of "Directly Affected" - Environmental Protection and Enhancement Act

Summary

This was an appeal of a judicial review upholding a decision of the Alberta Environmental Appeals Board ("Board"). The Board refused to hear an appeal of an approval granted by the designated director of approvals (the "Director") permitting the respondent, Secure Energy Services Inc. ("Secure Energy") to accept and dispose of certain naturally occurring radioactive material (sometimes referred to as "NORM") in its Pembina Landfill near Drayton Valley, Alberta.

The appellant Normtek Radiation Services Ltd. ("Normtek") sought judicial review of the Board's decision and an order quashing it on the ground that the Board employed an unduly restrictive, and therefore unreasonable, interpretation of the phrase "directly affected" in sections 91(1)(a)(i) and 95(5)(a)(ii) of the *Environmental Protection and Enhancement Act* (the "*EPEA*"). Normtek's application for judicial review was dismissed on the basis that the Board's finding that Normtek was not directly affected by the Director's decision was reasonable.

The Court of Appeal (the "Court") allowed Normtek's appeal of the order of the judicial review judge, and remitted the matter back to the Board to decide the matter of Normtek's standing to appeal the Director's decision. The Court held that both the Board and the judicial review judge adopted an unreasonable and unjustifiably restrictive interpretation of the phrase "directly affected". It also found that section 95(5) of *EPEA* does not confer jurisdiction on the Board to hear appeals of Directors' decisions by persons who are not directly affected by those decisions.

Application for Director's Approval

The process which led to the appeal began with Secure Energy applying to the Director for approval of an amendment to its existing Class I landfill approval. The amendment was sought to permit the receipt of concentrated naturally occurring radioactive material at Secure Energy's Pembina landfill northwest of Drayton Valley.

Normtek's Statement of Concern

The *EPEA* provides that any person who is directly affected by a Director's decision may submit to the Director a written statement of concern setting out that person's concerns with respect to the decision. The Court noted that the appellant Normtek is in the business of decontaminating naturally occurring radioactive material which become unnaturally accumulated or concentrated in oilfield waste or on oilfield equipment as a consequence of oil and gas extraction and production operations. Normtek then disposes of the radioactive material either in an approved landfill or in a secure subterranean geological formation, depending on the level of the material's radioactivity.

Normtek responded to Secure Energy's application for approval by submitting a statement of concern to the Director indicating its concerns with the proposal to landfill radioactive waste material with a radioactivity concentration of higher than 5-10 Bq/g rather than dispose of it in a subterranean geological formation. Secure Energy's proposal was to landfill NORM up to 70 Bq/g. A Bq or Becquerel is a measure of radioactivity. A Bequerel is one nuclear transformation or disintegration per second. Normtek argued that generally-accepted industry standards and national and international guidelines suggest that Secure Energy was proposing to landfill radioactive wastes that ought properly to be disposed of in a secure subterranean geological formation.

Normtek contended that the landfilling of naturally occurring radioactive material which becomes concentrated in oil field waste is only appropriate for low radioactivity level material (5-10 Bq/g). Higher radioactivity level NORM, such as that proposed to be landfilled at Secure Energy's Pembina Landfill (up to 70 Bq/g), Normtek submitted, is typically sent for geological disposal in salt caverns in Saskatchewan. Normtek's statement of concern also pointed to the lack of a provincial regulatory regime for NORM.

In response to a question from the Director, Normtek acknowledged that it did not have any land holdings in the vicinity of the landfill, but submitted that factors other than ownership of land near the proposed activity can give rise to being directly affected. Normtek submitted that an approval would change the way NORM disposal was currently being conducted. Normtek argued that the approval would give Secure Energy a competitive advantage over anyone in the business of disposing high activity naturally occurring radioactive material because Secure Energy proposed to simply dispose of such radioactive waste in its landfill, rather than manage it in accordance with what Normtek submitted were generally accepted best practices. Normtek submitted if the applied-for approval was given, high level radioactive materials which had hitherto only been permitted to be disposed of in underground geological formations would now be allowed to be disposed of near the surface.

Alberta Environment's District Approvals Manager (on behalf of the Director) responded by stating that Normtek's place of residence was outside of the area of environmental impact associated with the proposed project. Normtek was therefore not considered directly affected, and its submission was not considered a statement of concern.

Director's Decision (Approval)

The Director issued an approval amending Secure Energy's landfill approval to permit it to receive and dispose of NORM waste that did not exceed certain prescribed maximum concentration limits (70 Bq/g) as proposed by Secure Energy. The approval also required Secure Energy to operate the landfill in accordance with the "Canadian Guidelines for the Management of Naturally Occurring Radioactive Materials" ("Guidelines"). Among other things, the Guidelines set maximum concentration acceptance limits for NORM dispersed in soils and other media.

The Court noted that the Director's approval expressly required the approval holder to operate its landfill in accordance with these Guidelines. Yet the Director's approval also expressly prescribed certain radioactivity limits for materials accepted by the landfill which appeared to be expressed in a multiple of the concentration limits (10 times the concentration limits) for exempt material set out in certain International Atomic Energy Association Regulations. Normtek's position was that the federal Guidelines and the so-called International Atomic Energy Association Regulations were violated by the very terms of the approval which purported to incorporate them.

Normtek's Appeal of Director's Decision and Environmental Appeal Board's Decision on Standing

Normtek filed a notice of appeal of the Director's decision approving the acceptance of NORM at Secure Energy's Pembina Landfill. Following further submissions on standing, the Board's decision was that Normtek did not provide sufficient evidence to demonstrate that it was directly affected by the amending approval. The Board's reasons were that Normtek's concerns were primarily commercial or economic and that Normtek failed to demonstrate that its use of a natural resource would be affected by the amending approval.

Judicial Review of the Environmental Appeals Board's Decision on Standing

Normtek's application for judicial review was dismissed. The reviewing judge found that the Board's interpretation and application of the phrase "directly affected" in the *EPEA* was reasonable. The reviewing judge also found that the *EPEA* does not permit a person who is not directly affected by a decision of the Director to appeal a Director's decision.

Court of Appeal Analysis

The Court found that the Board's interpretation of "directly affected" as requiring the would-be appellant to establish that the Director's decision would harm the appellant's use of a natural resource near the approved activity is not only inconsistent with the *EPEA*, but also is not supported by many of the Board and court decisions which the Board cited. The Court found that the Board and the chambers judge were unreasonable in concluding that an adverse impact cannot qualify a person as being "directly affected" unless the adverse impact is on the appellant's actual use of a natural resource near the activity which the Director has approved.

The Court noted that the economic interest, which Normek argued was directly affected, was based on its interest in ensuring that naturally occurring radioactive materials are managed in accordance with generally accepted regulatory standards to which it said it was required to adhere. Properly understood, Normtek's concern was as much regulatory concern as it was an economic or commercial concern. The Court also stated that Normtek's standing argument was as much directed at the Director's decision as it was at the activity which Secure Energy obtained approval to engage in. The "interest" which Normtek argued was directly affected, was its interest in ensuring radioactive materials are managed in a manner which it claimed complied with generally-accepted regulatory standards which it was required to observe.

The Court noted that the Environmental Appeals Board is not a regulator like some of Alberta's energy boards. The Board is essentially an independent commission of inquiry reporting to the Minister. It was established to provide the Minister with independent and expert advice with respect to such regulation by reporting to the Minister a summary of the representations which were made to it and any recommendations it might have as a result of those representations (s 99(1)).

The Court stated that one of the goals of the *EPEA,* when it was introduced, was to achieve better environmental decision-making. The Board process was set up to help achieve that. By granting standing to those directly affected by Directors' decisions, the Minister receives the benefit of additional scrutiny which, in the case of directly affected industry participants, provides the Minister with a practical understanding of the effects of conditions of approvals, which industry participants are in a unique position to provide. The integration of environmental protection and economic impacts is one of the purposes of the *EPEA* (ss 2(b) and 2(c)) and hearing appeals by those impacted economically helps the Minister achieve that purpose.

The Court found that the decisions of the Board and the reviewing judge that the economic effects of an approval are not enough to ground standing unless the economic effects can be linked back to the environment were unreasonable. However, the Court found that in any event, Normtek did present evidence which linked the economic impact on it back to the environment. That evidence was not dealt with by the Board, because the Board failed to consider relevant evidence.

<u>The Burden of Demonstrating that a Person is "Directly Affected"</u>

The Court noted that the Board relied on Rule 29 of its *Rules of Practice*, suggesting that it is clear that the onus is on the appellant to prove that it is directly affected. The Court held that the only onus this rule imposes is to adduce evidence in support of one's position, which Normtek did. Furthermore, the onus on the appellant, when its standing is challenged, is not to prove conclusively that it is directly affected, but to establish a reasonable possibility that it will be directly affected by the Director's decision.

<u>Discretion to Hear an Appeal by a Person Not Directly Affected</u>

The Court held that the Board does not have the discretion or jurisdiction to hear public interest appeals by a person who is not directly affected. An activity the Director approves may directly affect a large segment of the public which potentially might make the class of persons directly affected very large; but that is not the same as granting standing to a person who has been found not to be directly affected. The *EPEA* clearly does not confer jurisdiction on the Board to grant public interest standing to a party who the Board finds is not directly affected. Nor does current jurisprudence confer such jurisdiction on administrative tribunals in the absence of clear statutory authority.

<u>Court's Disposition</u>

The Court found the Board's interpretation of "directly affected" in the *EPEA* too restrictive, and remitted the matter of Normtek's directly affected status to be decided by the Board. The Court noted that the Board must determine whether it is of the opinion that Normtek is directly affected by the decision of the Director. The Court expressed no view on that issue, but noted that the Board must not decide the issue employing the restrictive interpretation of "directly affected" which it employed in this case. It must decide the issue having regard to the provisions of the *EPEA* and the evidence relevant to the determination to be made.

The appeal from the judicial review judge's decision was allowed on the issue of the Board's interpretation of "directly affected" in section 91(1()(a)(i) of the *EPEA.* The appeal from the judicial review judge's decision on the jurisdiction of the Board to entertain appeals from persons not directly affected was dismissed.

ALBERTA ENERGY REGULATOR

Late Request for Regulatory Appeal or Reconsideration by an Individual - Declaration Naming an Individual Pursuant to Section 106(1) of the Oil and Gas Conservation Act, **Regulatory Appeal No. 1931598**
Regulatory Appeal - Extension of Time - Section 106 OGCA

This decision dealt with an individual's request for a regulatory appeal filed on March 10, 2020 ("Request") of an AER decision dated April 19, 2019 ("Decision") issued pursuant to section 106 of the *Oil and Gas Conservation Act* (the "*OGCA*"). The individual also requested that the AER extend the time limit for filing of the Request or, alternatively, that the AER exercise its discretion and reconsider the Decision in accordance with section 42 of the *Responsible Energy Development Act* (the "*REDA*").

The AER considered the individual's request under section 38 of the *REDA* for a regulatory appeal of the Decision. The AER decided that there were compelling reasons and special circumstances that warranted allowing the late filing of the Request. Further, the AER decided that the individual is eligible to request a regulatory appeal in this matter and therefore granted the Regulatory Appeal.

<u>AER Analysis</u>

There were two questions that were addressed. The first question was whether the AER should grant the late filing of the Request and the second question was whether the regulatory appeal should be granted and the matter referred to a hearing.

Lateness of the Request

The AER noted that statutory time limits for filing appeals of AER decisions serve important purposes. They provide a level of certainty to parties as to the validity and reliability of a decision. They also give assurance that proceedings relating to a decision will not continue into perpetuity. Requests for Regulatory appeals must be filed on time, unless there is a valid reason to depart from this requirement. The reason must be compelling or there must be special circumstances for making an exception. Factors such as why the request was not filed on time, the amount of time that has elapsed since the deadline, the significance of the decision and its impact on the requester, and the prejudice suffered by a party if the request is or is not allowed to be filed are all relevant when considering requests to extend the timelines for filing regulatory appeal requests under the AER's Rules of Practice.

The AER noted that the individual's counsel indicated he was not aware of the regulatory appeal process or its timelines until he consulted with counsel. However, the final paragraph in the letter accompanying the Decision clearly states that eligible persons may appeal AER decisions, provides the sections in the *REDA* where one should look to find out more about regulatory appeal requests, and directs the reader to the AER's website for further information, including filing requirements and forms. The AER was of the view that the individual had sufficient information about the regulatory appeal process at the time the decision was issued to him but that he failed, or chose not to, review this information or inform himself further about the regulatory appeal process.

The AER noted that it was not helpful to the individual's case that it took him approximately 10 months after the Decision was issued to make inquiries with a lawyer as to the proper processes involved with filing an appeal. He did not file his request until March 10, 2020, nearly 11 months after the Decision. The AER noted that the tardiness of the Request and his failure to follow instruction provided to him about the regulatory appeal process were significant factors and weighed strongly against extending the timeline for filing his Request.

However, the main factor in favour of granting the Request to be filed late is the significant and adverse impact a s.106 declaration has against him personally. The AER noted that other than the AER's Compliance and Liability Management group ("CLM Group") there is no other party prejudiced by the lateness of the individual's request. If there were, this could easily have tilted the scales in favour of not allowing the request to be filed. As it is, the substantive impact of the Decision to the individual is at least as significant as the procedural irregularity and prejudice to the CLM Group that may be caused by allowing the late filing of his Request.

The AER also noted that the multiple correspondences that the CLM Group sent out regarding the declaration(s) would have been confusing for the individual in understanding the AER's s. 106 appeal request process. There was the initial declaration issued on March 11, 2019, without considering the individual's January 28, 2019 submission. Second, and as admitted by the CLM Group, the reconsideration letter issued on March 22, 2019 was issued by someone without the appropriate statutory authority. The AER also noted that when the individual began trying to access the AER's internal appeal processes by asking the CLM Group staff to 'reconsider' the Decision, he was not told that there was a more suitable process available and was not directed to the AER's Regulatory Appeal coordinator for further information about the regulatory appeal process. The CLM Group accepted the individual's 'reconsideration' requests filed on April 1 and 3, 2019. The AER noted that all the above could have served to further confuse the individual as to the AER's processes, and may even have created the expectation that he was 'on the right track' as far as appealing the Decision.

Consequently, the AER found that there were special circumstances and sufficient reasons that, on balance and by a very slim margin, warranted accepting the late filing of the Request.

<u>The Merits of the Request</u>

With regard to the eligibility question, the AER found that the individual is directly and adversely affected by the Decision, which imposes both obligations and restrictions on him, which is the purpose of declarations issued under section 106 of the *OGCA*. He is therefore an eligible person to request the regulatory appeal. The Decision was made pursuant to an energy enactment and is an appealable decision in accordance with the applicable provisions of the *REDA* and the AER Rules.

Consequently, the Request was granted and the matter was referred to a hearing before an AER panel of hearing commissioners for a further process to be determined by that panel. Given this, the AER found it unnecessary to determine the individual's request for reconsideration.

ALBERTA UTILITIES COMMISSION

***Market Surveillance Administrator Proposes Amendments to AUC Rule 019,* AUC Bulletin 2020-41**
Application to ISO Rules - Penalty Escalation

The AUC seeks stakeholder feedback on revisions to AUC Rule 019: *Specific Penalties for Contravention of ISO Rules* ("*Rule 019*") proposed by the Market Surveillance Administrator ("MSA").

The AUC proposes to accept the following MSA-recommended amendments to *Rule 019*:

- *Rule 019* would apply to all independent system operator ("ISO") rules;
- the three categories of contraventions be collapsed into one category; and
- the penalty escalation found in the Category 1 table be the one used to determine the penalty amount for subsequent contraventions of the same ISO rule.

The AUC review of *Rule 019* will consist of a stakeholder consultation involving a written process.

***Amendments to AUC Rules 002, 003, 021 and 028 to Reduce Regulatory Burden and Improve Efficiency*, AUC Bulletin 2020-42**
Administrative Efficiency - Updating Filing Requirements

Following the introduction of the *Red Tape Reduction Act* by the government of Alberta the AUC made further rule amendments to reduce the regulatory requirements contained within the rules.

Rule 021 and Rule 028 served as the operational manuals for the estimated combined $8 billion electricity and natural gas markets. Recognizing the critical nature of these rules, the AUC met extensively with stakeholders over several months.

In November 2020, the AUC initiated a rule-review process through its engage consultation platform in which it sought feedback from stakeholders on changes to Rules 002, 003, 021 and 028. The proposed changes focused on removing unnecessary requirements, streamlining and updating filing requirements, and improving administrative efficiency.

This bulletin, the final approved Rules 002, 003, 021 and 028, along with the corresponding blackline version of the rules, and the AUC responses to stakeholder comment tables were posted in the rule-related consultations section of the AUC website. The changes to the rules apply immediately, and stakeholders can take advantage of the reduced regulatory requirements in these rules immediately.

***Alberta Electric System Operator 2021 Balancing Pool Consumer Allocation Rider F Application,* AUC Decision 26040-D01-2020**
DTS Market Participants - DOS Market Participant

In this decision, the AUC approved the application from the Alberta Electric System Operator ("AESO") for its 2021 Rider F - Balancing Pool Consumer Allocation rider ("2021 Rider F"). The AUC approved a $2.30 per megawatt hour ("MWh") Rider F charge to all demand transmission service ("DTS") and demand opportunity service ("DOS") market participants, except for the City of Medicine Hat ("Medicine Hat") and BC Hydro at Fort Nelson, for metered energy from January 1, 2021, through December 31, 2021. The AUC also approved the AESO's removal of Section 2(2) from the 2021 Rider F.

<u>Background</u>

The Balancing Pool is a corporation established by section 75 of the *Electric Utilities Act* ("*EUA*") to carry out the powers and duties set out therein. Pursuant to section 82 of the *EUA*, the Balancing Pool is required to prepare a budget for each fiscal year setting out its estimated revenues and expenses. Based on the forecast revenues and expenses in its budget, the Balancing Pool must determine an annualized amount that would be refunded to (or collected from) electricity market participants over the year. The AESO was required to include this annualized amount in its tariff.

The AESO collects or refunds the Balancing Pool's annualized amount through Rider F. Rider F applies to system access service ("SAS") provided under Rate DTS of the Independent System Operator ("ISO") tariff and Rate DOS of the ISO tariff. Rider F does not apply to SAS provided to Medicine Hat or BC Hydro at Fort Nelson.

<u>Rider F for 2021</u>

The AESO was notified by the Balancing Pool of a negative annual forecast amount of $134,317,470 for 2021 and approved a charge of $2.30/MWh of consumption. The AESO consequently applied for approval of a $2.30/MWh Rider F charge for metered energy from January 1, 2021, through December 31, 2021. The AESO stated that, apart from Section 2(2), the 2021 Rider F would remain substantively unchanged from the Rider F that was in effect for 2020 metered energy.

Section 2(2) of the 2020 approved Rider F required that the ISO determine Rider F to refund or collect an annualized amount estimated by the Balancing Pool and transferred to the ISO under section 82 of the *EUA*, for the market participants receiving SAS from the ISO under Rate DTS or Rate DOS of the ISO tariff.

<u>AUC Findings</u>

The AUC found it reasonable for the AESO to remove Section 2(2) of the previously approved Rider F. It agreed with the AESO's statement that this section repeats the requirements set out in sections 30(2)(b) and 82 of the *EUA* and Section 1 of Rider F.

In the absence of objections to the allocation proposed or any evidence filed to demonstrate that the AESO's approach to calculating Rider F was unjust, unreasonable or unduly preferential, arbitrary or discriminatory, the AUC approved the annualized amount of negative $134,317,470 and its allocation Rider F charge of $2.30/MWh of metered energy as determined by the AESO.

Alberta Electric System Operator - Decision on 2020 Rider A1 Extension Application, **AUC Decision 25670-D01-2020**

Criteria for Extension of Duplication Avoidance Tariff

In this decision, the AUC approved the extension of Rider A1 for the period January 1, 2022, to December 31, 2041.

<u>Background</u>

The Alberta Electric System Operator ("AESO") filed an application with the AUC, requesting an extension of Rider A1 to its Independent System Operator ("ISO") tariff. The rider was originally approved for the Dow Fort Saskatchewan plant complex ("Dow") by the Alberta Energy and Utilities Board, predecessor to the AUC, for a period of 24 years, ending in December 2021. In the current application, the AESO requested the approval of a 20-year extension, from January 1, 2022, to December 31,2041.

Rider A1 is a transmission Duplication Avoidance Tariff ("DAT") originally adopted to provide Dow with system access service in response to Dow's credible opportunity to construct a physical bypass of existing transmission facilities. Rider A1 was designed to keep Dow neutral between the cost of using existing transmission facilities or building its physical bypass option.

<u>Extension of Rider A1</u>

As part of the original Rider A1 application approved in 1998, Dow made two monetary contributions totalling $5,071,038 to the AESO related to the costs of the physical facilities. A schedule was also created for Dow to pay ongoing operating and maintenance ("O&M") costs over a 24-year period, ending on December 31, 2021. The monthly payment approved for Rider A1 varied from a high of $72,115 in 1999, to a low of $19,361 in 2021.

As part of the extension the AESO included the incremental loss factor and a schedule of monthly O&M payments from Dow to the AESO for the period from January 1, 2022, to December 31, 2041. These monthly payments gradually increase from $21,037 in 2022, to $30,647 in 2041. The AESO submitted that an extension to the rider was reasonable because, had the facilities contemplated in Decision U98125 been constructed, they would have had a service life of 40 – 60 years.

The AESO explained that its proposed form of Rider A1 extension continues the original 24-year operating cost payment schedule to December 31, 2041, and that Dow has agreed to set those payments according to the same methodology used in 1998. This methodology was based on the estimated O&M costs, spare parts inventory, overhead, and losses that the virtual transmission assets would have incurred.

<u>Findings</u>

The AUC applied the criteria previously applied in applications for the extension of a DAT. That is, the extension of the term of the DAT should be: (i) by agreement of the parties; (ii) with notice to the AUC and interested parties; and (iii), reasonable.

The AUC was satisfied that the first two criteria were met. The AESO and Dow agreed on the terms of an extension to submit the application, and by its filing, both the AUC and interested parties have had notice. With respect to the reasonableness of the extension, the AUC found that the factors considered when the initial bypass was granted provided some guidance:

- Would the statutory provisions under the *Electric Utilities Act* ("*EUA*") in effect allow Dow to bypass the *EUA's* requirements to obtain transmission service from the distribution owner as set out in Section 5 of the *EUA*?

- Was Dow's physical bypass option economically viable?

- Would the rider prevent the unnecessary construction of redundant facilities and shelter transmission customers from the costs of absorbing stranded assets?

- Was the rider amount no more attractive, than was reasonably required, to avoid duplicate facilities?

Applying these principles to the extension requested, the AUC found that:

(a) Pursuant to section 117(1) of the *EUA*, an industrial system designation ("ISD") order issued by the AUC includes a condition specifying that the electric energy produced from and consumed by the subject industrial system is exempt from the operation of the *EUA.* Accordingly, the granting of the ISD confirms that Dow satisfies the statutory prerequisites for an exemption.

(b) The bypass rate was approved on the basis that a bypass facility would have been economically viable and if it had been built, it would have been in service for roughly 40 to 60 years. The extension reflects the end of the 40-year period and on this basis, the AUC found the extension to reasonably represent a viable bypass option.

(c) The AUC accepted the AESO's evidence that the rate negotiated is reasonably reflective of the remaining O&M costs and is no greater than reasonably required.

The AUC therefore approved the extension of Rider A1.

***Alberta Electric System Operator - Decision on 2021 Independent System Operator Tariff Update*, AUC Decision 26054-D01-2020**
ISO Tariff

In this decision, the AUC approved the application from the Alberta Electric System Operator ("AESO") for its 2021 update to the Independent System Operator ("ISO") tariff.

Background

In its application, the AESO requested approval of changes to the levels of various rates, Rider J, and Section 8 of the ISO tariff. The application included minor changes to the terms and conditions of the AESO's 2018 ISO tariff, as updated in this application, for the year 2021.The AESO stated that its 2021 ISO tariff update application reflected an overall increase of 1.5 percent over the 2020 rates then in effect.

The AESO also made changes to the tariff to reflect the removal of the regulated generating unit connection cost charge schedule, which expired at the end of 2020, and a change to a clause in the proforma system access service contracts.

The AESO requested that the updated rates, riders and maximum investment levels proposed in its application apply on a go-forward basis only, commencing from the effective date approved by the AUC. The AESO submitted that the currently approved deferral account rider and reconciliation mechanisms continue to be used to address any variances between costs and revenues occurring prior to the approval of the applied-for rates. The AESO also indicated that it is not seeking any retroactive adjustments to the rates proposed in this application.

The AESO filed the present annual tariff update application to reflect costs and billing determinants for the 2021 calendar year, and changes resulting from the AUC's acceptance, amongst other matters, of the 2018 Transmission Cost Causation Study update in Decision 22942-D02-2019.

Application Details

The AESO's tariff update application consisted, in part, of formulaic updates to annual revenue requirement, rates, riders and maximum investment levels, and a 2021 escalation factor.

The AESO's Annual Revenue Requirement

The AESO's revenue requirement consisted of costs related to wires, ancillary services, transmission line losses, and the AESO's own administration (which included other industry costs and general and administrative costs). A comparison of the AESO's 2021 forecast, 2020 forecast and 2019 - 2018 recorded costs, was reproduced in the following table.

Table 1. Comparison of 2021 forecast, 2020 forecast and 2019-2018 recorded costs by revenue requirement components

Cost component	2021 forecast	2020 forecast	2019 recorded	2018 recorded
	($ million)			
Wires	1,951.6	1,916.0	1,849.7	1,782.5
Ancillary services	198.3	258.4	213.0	277.8
Losses	104.4	113.5	106.5	98.3
Administrative	114.5	99.1	112.4	104.5
Revenue requirement	**2,368.8**	**2,387.0**	**2,281.6**	**2,263.1**

Source: Exhibit 26054-X0002.01, application, Table 2-1, PDF page 6.

Rate Calculations and Billing Determinants

The rate calculations for the 2021 rates update are based on the AESO's forecast of billing determinants for 2021 which are calculated using historical and year-to-date ratios between Demand Transmission Service ("DTS") energy and each individual billing determinant.

Billing determinants changed from the 2020 forecast on which the currently approved rates were based. Consequently, the AESO's 2021 updated rates increase 1.5 percent overall from the approved 2020 rates, including an increase of 1.6 percent to Rate DTS, and a decrease of 1.9 percent to Rate Supply Transmission Service ("STS").

2021 Maximum Investment Levels

The application included updated investment amounts approved in the 2018 ISO tariff application that reflect an escalation factor based on a composite of specified recent inflation indices. The AESO updated the composite inflation index used for developing the point-of-delivery (POD) cost function to 2021, using additional Statistics Canada cost index values and the most recent Conference Board of Canada forecast of the Alberta Consumer Price Index ("CPI").

The AESO applied the resulting escalation factor, 1.0641, to the 2018 Rate DTS maximum investment levels to determine the 2021 Rate DTS maximum investment levels, which resulted in an increase to the 2018 maximum investment levels.

Regulated Generating Unit Connection Costs

The AESO proposed revisions to the 2021 ISO tariff that reflect the removal of the regulated generating unit connection cost ("RGUCC") provisions. Because the RGUCC charge component of Rate STS only applies if a regulated generating unit terminates its system access service contract with the AESO prior to the expiry of the regulated generating unit's base life, and no regulated generating units have a base life that extends past 2020, the AESO proposed removing the RGUCC provisions in the current 2021 ISO tariff update.

Generating Unit Owner's Contribution Rates

The generating unit owner's contribution ("GUOC") rates proposed by the AESO in the 2018 application were approved by the AUC in Decision 22942-D02-2019. The AESO stated that its planning and engineering studies have not identified a need to update the GUOC rates. As a result, the AESO's proposed GUOC rates are unchanged from those approved in its 2018 application.

Findings

In Decision 2010-606, the AUC approved an approach that included filing comprehensive tariff applications every three years and, in conjunction with this, filing annual tariff updates. The AUC considered that an annual revenue requirement and rate update may benefit customers by limiting potential misallocations that might occur if the AESO were to rely on Rider C exclusively to allocate periodic revenue and cost imbalances to its customers.

The AUC was satisfied that the AESO included the 2021 wires costs for TFOs using the AUC's approved approach.

The AUC acknowledged that the AESO's 2021 forecast for ancillary services, losses and administrative costs included in the current application have yet to be approved by the AESO board as final. The AESO proposed to file a letter to advise the AUC of AESO board approval once it has been received. The AUC directed the AESO to submit the letter confirming AESO board approval by January 31, 2021. Any differences arising between the forecast amounts included in this application and the AESO board-approved costs or the AESO's actual costs will have to be settled through Rider C.

The AUC found that the AESO's 2021 forecast billing determinants used in the tariff update application were reasonable given that certain billing determinants have been decreasing and impacts of the COVID-19 pandemic are expected to continue in 2021.

The AUC was also satisfied that maximum investment level amounts, calculated based on an escalation factor of 1.0641 applied to a composite of specified recent inflation indices, are consistent with the rate calculation approved methodology.

Given that no regulated generating units have a base life that extends past 2020, the AUC found that it is reasonable for the AESO to remove the RGUCC provisions in the current 2021 ISO tariff update.

For all of the above reasons, the AESO's 2021 ISO tariff update application was approved.

***AltaLink Management Ltd. and TransAlta Corporation Direct Assigned Capital Deferral Account for the Edmonton Region Project,* AUC Decision 25369-D01-2020**
Prudence of Costs - Indigenous Cooperation Agreements

In this decision, the AUC determined that not all costs applied for in the deferral account reconciliation application by AltaLink Management Ltd. ("AML") and TransAlta Corporation ("TransAlta") were prudently incurred. The AUC did not approve all of the applied-for rate base capital additions for the Edmonton Region 240 kilovolt ("kV") Upgrades Project (the "Project").

AML and TransAlta applied for approval of final capital costs for the Project of $90.9 million for AML and $21.6 million for TransAlta.

The AUC found that AML and TransAlta did not prudently plan and execute 8 kilometres ("km") of Project, constructed across Stoney Plain Reserve #135 (the "Reserve"). The AUC disallowed fifteen percent of the costs associated with the construction of this section of transmission line, net of the costs of the Cooperation Agreement. The AUC disallowed a similar percentage of the costs incurred by the utilities to negotiate and conclude the Cooperation Agreement. The total amount disallowed in the decision was approximately $3 million, which represents slightly less than one percent of the total capital additions requested.

<u>Background</u>

The Project consisted of the construction of a 240 kilovolt ("kV") transmission line 1043L located between Keephills 320P Substation and the Jack Fish Lake area west of Edmonton. The portion of the Project that was the subject of this application, the 1043L line, included a new 12 km 1043L double-circuit 240 kV line from the 240 kV junction to Jackfish Lake. Also part of this proceeding was the rebuild of 904L, consisting of 50 km of single-circuit 240 kV H-Frame line from Jackfish Lake to Petrolia 816S Substation. The rebuild portion of the project scope included the 8 km of line within the existing right of way ("ROW") on the Reserve. The rebuild of transmission line 904L was renamed 1043L.

The Project and associated costs were divided into two portions: 1043L (the portion of the Project not on the Reserve, 54 km) and 1043L-Reserve (the 8 km portion of the Project on the Reserve).

TransAlta was the transmission facility owner ("TFO") of 1043L-Reserve. AML and TransAlta have an Operations and Maintenance Agreement in which AltaLink provided certain operation and maintenance services for transmission facilities located on First Nations' reserves including the Enoch Cree First Nation's ("Enoch") reserve.

Construction on 1043L began in October 2011 following approval of the Project by the AUC. Construction on 1043L-Reserve began in December 2011 and stopped in May 2012 at the request of Enoch's Chief and Council, who stated they had concerns about the Project. Following the resolution of land access disputes, which included a Cooperation Agreement with Enoch, the Project was completed on September 29, 2016 and 1043L was energized.

Direct Assigned Deferral Account Application

In its direct assign capital deferral account ("DACDA") reconciliation application AML requested an approval and reconciliation of capital additions to December 31, 2018, totalling $90.9 million in respect of the Project. Within the same proceeding, TransAlta filed its DACDA. It relied on relevant exhibits previously filed within TransAlta's 2015-2016 general tariff application ("GTA"), and TransAlta's 2017-2018 GTA.

Cost Summary

In this application, AML sought approval of $90.9 million in costs. TransAlta applied for approval of $21.6 million in costs. The AUC previously directed that TransAlta's proposed reconciliation of its capital deferral account for the Project be examined, together with AML's capital costs on the same project, in a single proceeding. The AUC approved three placeholders for 2016: a capital addition of $19,017,065; a portion for an allowance for funds used during construction ("AFUDC"); and $280,000 as an operating cost.

For 2017 and 2018, the AUC approved placeholders for the project including trailing costs of $23,000 and a credit adjustment of negative $521,000. These would reflect that costs originally capitalized to the Project had either been reallocated as salvage costs or reassigned as an AML cost. The AUC further approved the inclusion of the $ 280,000 payments to Enoch for each of the years 2017 and 2018 as part of TransAlta's revenue requirement for those years on a placeholder basis.

As of December 31, 2018, the Project had incurred actual costs of $135.1 million. AML's portion of those costs totalled $113.6 million.

<u>Prudency Assessment of Costs</u>

1043L - Facilities Not on the Reserve

The AUC noted that the off-reserve portions of the line were constructed on schedule and that cost variances were reasonably explained. The AUC approved the costs for this portion of the 1043L project.

1043L-Reserve - Facilities on the Reserve

TransAlta's costs associated with 1043L-Reserve were $21.6 million, including the costs for the Cooperation Agreement with Enoch for the right of way ("ROW") access.

The Cooperation Agreement included payments of $250,000 for construction access, $700,000 for a traditional land use and area structure plan and a contribution of $150,000 towards the legal costs of Enoch and $50,000 for an annual structure payment study. The Consumers' Coalition of Alberta ("CCA") recommended a disallowance of $575,000, or 50 percent, of these costs.

<u>AUC Findings</u>

The AUC found that a disallowance of some costs for rebuilding line 1043L-Reserve was warranted. It also found that the payments of $1.15 million set out in the Cooperation Agreement were properly incurred and should be approved. The AUC further found that a disallowance was necessary for the costs incurred by the utilities to negotiate and conclude the Cooperation Agreement.

The AUC's focus of necessity was not limited to the applicants' conduct while engaged in construction-related activities on the reserve. The AUC was also concerned with the extent to which the applicants' consultation-related conduct prior to the initial work stoppage could have affected the overall level of costs incurred on the reserve portion of the Project.

The AUC found that the applicants had failed to establish, on the balance of probabilities, that all their costs of rebuilding transmission line 1043L on the reserve were prudently incurred. The failure of the applicant to establish that all costs related to on-reserve activities sought to be recovered in this proceeding were prudently incurred arose mainly from their failure to properly demonstrate that they had met the consultation requirements set out in Rule 007.

The AUC found that there was little doubt that by the end of June 2010, AML and TransAlta had been made well aware by Enoch of its financial interests and concerns. For a year prior to AML filing its facilities application on July 28, 2010, AML and TransAlta engaged in a series of consultations with the representatives of Enoch. As required by Rule 007, these consultations were well recorded. During these consultations, Enoch raised issues mainly focused on economic compensation and related benefits for the community.

Despite the commitments made by AML to Enoch, regarding discussions with the First Nations about the Project and notifying them of construction and maintenance activities, there was no record of any communications during a period of one year and four months, until two months before AML restarted construction.

The AUC found that TransAlta's explanation of the lack of records of any consultation with Enoch would not transform a failure to act reasonably or prudently in maintaining complete records as required by Rule 007 into something inconsequential. The AUC noted that the explanation would not in any way assist the applicant in meeting their requirement of proving that their conduct was prudent or reasonable and likely to lead to completion of construction of 1043L-Reserve on budget and on time.

The AUC limited its findings on the question of whether and to what extent expenditures on the Project were prudently incurred. The AUC determined that the applicants had failed to establish, on the balance of probabilities, that their conduct related to Project consultations with Enoch between July 2010 and May 2012 had been prudent and reasonable.

As a result, the AUC found that not all costs were reasonably incurred. It found and directed that it would be reasonable to reduce the amount of expenditures eligible for recovery by the applicant by 15 percent. The AUC further found it reasonable for the recoverable amount of legal and related costs incurred by the utilities associated with negotiating and concluding the Cooperation Agreement to be reduced by 15 percent. The AUC left it to the applicants in both cases to determine themselves the appropriate division of the disallowance of funds expended.

TransAlta estimated the costs associated with the only viable re-route, suited to curtail the work stoppage, to be $60 million. The AUC found this amount to have been far more than the actual costs incurred in rebuilding the line through the reserve.

Regarding the CCA's comments on the costs incurred in relation to the Cooperation Agreement, the AUC found that the negotiations between AML, TransAlta and Enoch were necessary to address historical concerns and assess issues. The AUC considered the costs of the Cooperation Agreement to have been reasonable.

***AltaLink Management Ltd. 2016 to 2018 Deferral Accounts Reconciliation Application*, AUC Decision 24681-D01-2020**

Rates

In this decision, the AUC made the following findings on the application from AltaLink Management Ltd. ("AML") for the disposition of certain deferral accounts in respect of the years 2016 through 2018:

(a) Regarding AML's request for approval of its reconciliation of its direct assign capital deferral account ("DACDA") in respect of the years 2016, 2017, and 2018, the AUC applied disallowances of approximately $4.7 million and $1 million in respect of the Medicine Hat 138 kV Area Reconfiguration and Red Deer Hazelwood 287S projects, respectively. The AUC approved AML's applied-for costs for all of AML's other projects during the 2016 to 2018 period, as filed.

(b) AML's request for the recovery of expenses from projects cancelled by the Alberta Electric System Operator ("AESO") in 2017 and 2018 was approved.

(c) AML's proposed disposition of deferral accounts for taxes other than income taxes, long-term debt, and annual structure payments was approved.

(d) AML's request for placeholder amounts in respect of two disputes that were active at the time of the application was approved.

(e) A refiling application to comply with the directions and disallowances made in this decision was to be completed on or before January 29, 2021.

<u>DACDA Common Matters</u>

DACDA Application Requirements

The AUC noted that the Consumers' Coalition of Alberta ("CCA") and AML devoted significant portions of their argument and reply to issues of onus, standard of proof, and prudence, which have been addressed repeatedly in previous decisions. Regarding the CCA's suggestion that the AUC applies different standards to its examinations of expenditures in ATCO Electric proceedings than it does to AML, the AUC noted that these assertions were reckless, and addressing them hampers regulatory efficiency. The AUC noted that its position on onus, standard of proof, and prudence should now be clear.

Project Management and Overhead Costs

The AUC reviewed the reasonableness of AML's requested project management / project controls / construction management ("PMPC") costs by examining the drivers of the variances outlined in AML's project summary reports ("PSRs") for each project to determine whether the costs incurred were consistent with prudent management of the risks encountered in the context of that project.

Land Costs

The AUC determined that the limitation of land costs to a maximum of 40 percent above AML's average per acre amount for the land cost category, as suggested by the CCA should not be applied as a disallowance from the applied-for land costs for specific projects. It also refused to impose additional reporting requirements for applications where land costs exceed the average cost per acre by 20 percent or more than $75,000 per acre.

Legal Costs

Capital additions for the projects under review in the application include approximately $6.6 million in combined external and internal legal costs, $5.8 million for completed projects and $0.8 million for cancelled projects, or less than one percent of the total costs of the projects on an aggregate basis. The AUC did not share issues regarding legal fees raised by the CCA. Following its own independent review of legal costs, the AUC was satisfied that AML's legal costs were reasonable and approved the costs.

Pipeline AC Mitigation Costs

The AUC accepted that AML's AC mitigation approach, practices and process were consistent with those approved in AML's 2014-2015 DACDA in which AC mitigation was extensively reviewed. The AUC was not persuaded by the CCA that it should revise its prior findings accepting AML's AC mitigation practices. The AUC further accepted AML's evidence that it had pursued low-cost solutions with facility owners where possible. The AC mitigation costs were approved as filed.

Salvage Costs

In response to a ruling issued in AML's 2016-2018 DACDA application, AML stated that it had incurred $12.74 million in costs related to salvaging certain assets being retired because of the construction of its direct assign projects during the years 2016 to 2018.

The AUC found that, despite a lack of detail in some areas and salvage costs incurred on the Blackie Area 138 kV and the Edmonton Region 240 kV upgrades projects having been under the proposal to provide service ("PPS") estimates by $0.75 million and $2.189 million, AML reasonably supported its expenditures as prudently incurred for all projects. AML's net salvage costs were approved as filed.

Although the AUC approved AML's net salvage costs, AML's evidence that it was not able to provide the costs associated with each specific salvage activity was of concern to the AUC, particularly because of the AUC's approval of AML's request to change its net salvage methodology in Decision 25870-D01-2020, effective 2019.

Placeholders

The AUC approved the placeholder treatment of costs associated with helix spacer dampers and the Sunny Brook Retention Pond in the amount requested. AML was directed to provide the outcome of the dispute resolution and the actual trailing cost amounts in a future DACDA proceeding.

Capitalization of Deferral Account Support Costs

While the AUC agreed that deferral account support costs may be capitalized, AML did not identify the quantum of those costs claimed in this proceeding. AML was directed to provide the quantum and an explanation of the costs in the compliance filing.

<u>Major System Projects</u>

AML Project Delivery Model and Project Risk Management Practices

AML's project delivery model had been assessed and approved in prior AUC decisions. Issues raised in this proceeding did not persuade the AUC to revise its prior findings.

Southern Alberta Transmission Reinforcement

The AUC reviewed the requested capital additions for the Blackie Area 138 kV project. It also reviewed the costs incurred for the southern Alberta transmission reinforcement ("SATR") Castle Rock Ridge to Chapel Rock Project (D.0311), and the SATR Cypress SVC Project (D.0315). The AUC approved these costs as filed. The AUC also approved the requested aggregate capital additions totalling approximately $30.9 million as trailing costs incurred on the SATR Bowmanton to Whitla Project (D.0304), the SATR Cassils to Bowmanton Project (D.0305), and the SATR South Foothills Transmission Project (D.0306).

With regard to the Medicine Hat 138 kV Area Reconfiguration, the AUC found that not all expenditures related to the Medicine Hat Project had been prudently incurred. The AUC therefore directed AML to reduce its total requested cumulative capital additions of $186,682,308 by 2.5 percent.

South and West of Edmonton Area Transmission Development

The AUC determined that all costs related to the South and West of Edmonton Area Transmission Development projects (collectively the "SWEATD") had been prudently incurred, although it directed that AltaLink address some issues differently in future, and include detailed cost-benefit analysis substantiating the prudence of material expenditures on mats.

Red Deer Area Transmission Development

Except for the Red Deer Hazelwood 287S Project (the "Hazelwood Project"), the Red Deer Area Transmission Development ("RDATD") subproject costs had been prudently incurred. The remaining RDATD projects were approved as filed.

With regard to the Hazelwood Project, AML requested the approval of capital additions net of salvage costs but inclusive of re-accrued AFUDC to December 31, 2018, for the Hazelwood Project of approximately $67.8 million, an increase of approximately $16.9 million from the PPS forecast cost and of $6.7 million from the PPS update forecast.

The AUC found that AML imprudently assessed the risk that the AUC could approve an alternate route and the alternate substation location. When an alternate route was approved by the AUC, AML did not reasonably mitigate the foreseeable risks associated with landowner consultations on the alternate route. This lack of mitigation led to cascading risks resulting from AML's inability to complete construction in the winter season. The failure to reasonably assess and mitigate each of these risks resulted in compounding impacts, associated delays and escalated costs that were avoidable under a more comprehensive and proactive risk management framework. The AUC found it just and reasonable to direct AML to reduce this total requested cumulative capital additions of $67.8 million by 1.5 percent.

<u>Outstanding Directions</u>

Direction 8 from Decision 22542-D02-2019

The AUC approved the placeholder amount for AML's PMPC costs to December 31, 2015. The 2016 to 2018 period trailing costs for the WATL Project of $32,236,486, which included AML's incremental PMPC costs beyond the $127,206,179 placeholder amount, were also approved.

Provision of Unit Cost Information

Because of AML's inability or reluctance to comply with this direction, the AUC would not continue to insist on this disclosure and relieved AML from complying with this direction. The AUC reminded AML that it would still be required to justify the costs.

Responses to Other Outstanding Directions

The AUC reviewed AML's responses to the directions summarized in Appendix 3 of this decision and found that AML compiled with outstanding directions from prior decisions.

<u>Compliance Filing</u>

Because of disallowances and other directions set out in this decision, the AUC directed AML to file its compliance filing application by January 29, 2021.

The AUC would consider AML's proposed true-ups in respect of AML's deferral account reconciliations for the years 2016, 2017 and 2018 considering the findings and directions set out in this decision as part of AML's compliance application. The AUC would also consider AML's request for the approval of the payment of interest pursuant to Rule 023 at that time.

***Apex Utilities Inc. 2021 Annual Performance-Based Regulation Rate Adjustment,* AUC Decision 25867-D01-2020**

Interim Approval

In this decision the AUC considered the 2021 annual performance-based regulation ("PBR") rate adjustment filing from Apex Utilities Inc., formerly AltaGas Utilities Inc. ("Apex" or "AUI"), and approved the following:

(a) The 2018 going-in rates and 2018 K-bar were approved as final; and

(b) The 2021 special charges, distribution service rates and the corresponding rate schedules attached to this decision were approved effective January 1, 2021.

Procedural Summary

On September 10, 2020, Apex (at that time still AUI) submitted its 2021 annual PBR rate adjustment filing to the AUC, requesting approval of its 2021 gas distribution service rates, special charges, billing determinants and corresponding rate schedules, to be effective January 1, 2021, on an interim basis.

In Decision 25608-D01-2020, the AUC denied the former AUI to utilize the Type 1 incremental capital funding mechanism for its Etzikom Lateral Project. The AUC directed the former AUI to file an adjustment to this application reflecting the denial. Apex complied with the direction by submitting an updated application on November 2, 2020.

On November 19, 2020, Apex advised the AUC that it changed its name from AltaGas Utilities Inc. to Apex Utilities Inc. On November 24, 2020, Apex filed a letter on the record of this proceeding confirming that the content of the application filed under the name AltaGas Utilities Inc. was correct for customers of the newly named Apex Utilities Inc.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor").

Apex's most recent annual rate filing dealing with 2020 PBR rates were approved on an interim basis in Decision 24883-D01-2019.

PBR Rate Adjustments

2021 PBR Indices and Annual Adjustments

The 2020 PBR plan for Apex provided a rate-setting mechanism based on a formula that adjusts revenue-per-customer annually by means of the I-X indexing mechanism plus specifically approved adjustments.

(a) I-X Index

The AUC reviewed Apex's calculation of the 2021 I factor and found it to be consistent with the methodology set out in Decision 20414-D01-2016 (Errata). Accordingly, the 2021 I factor of 2.42 percent and the resulting I-X index of 2.12 percent were approved.

(b) Y and Z Factor Materiality Threshold

Apex calculated the Y and Z materiality threshold to be $0.54 million in 2021. The AUC approved Apex's 2021 Y and Z factor materiality threshold.

(c) Y and Z Factors

Apex applied for a Y Factor amount of $ 1.88 million, including carrying costs. After reviewing the calculations and supporting materials the AUC found the applicable provisions of Rule 023 had been abided by and approved the applied for Y factor as filed. Apex did not apply for any Z factor adjustments in 2021.

(d) Q Value

After having found that Q was properly calculated and consistent with the approved methodology, the AUC approved the Q value of 0.38 percent as applied for.

(e) K-Bar Factor

Apex applied for the 2021 K-bar funding of $12.13 million, calculated as its 2021 required K-bar and 2019 K-bar true-up, which was approved.

(f) K Factor

In compliance with an AUC direction, Apex removed the 2020 Type 1 factor of $0.68 million, the 2019 Type 1 capital factor of 0.17 million and Type 1 capital carrying costs of $0.01 million. The 2021 capital funding amount will total $11.27 million.

(g) Forecast Billing Determinants

Apex submitted that the forecasted 2021 billing determinants it provided were based on the same methodology approved in Decision 24883-D01-2019. The AUC found that the applied billing methodology and the resulting 2021 forecast billing determinants were reasonable. The billing determinant was approved as applied for.

<u>2021 PBR Rates</u>

Distribution Rates

Regarding Apex's special charges and standard contribution amounts set out in its 2021 special charges schedule, AUI escalated its special charges by the I-X index and rounded them to the nearest whole dollar.

Apex provided typical customer bill impact schedules reflecting the 2021 proposed rates that would go into effect on January 1, 2021. According to Apex's calculations, these would range from -1.08 to -4.56 percent without commodity charges, but would become +8.82 percent to +24.90 percent when commodity charges had been included. Keeping the price component of the commodity charges unchanged would result in a customer bill impact of -0.54 percent to -1.98 percent.

AUC Findings

The AUC reviewed Apex's schedules and calculations that support its 2021 PBR rates and was satisfied they were reasonable and had been accurately calculated.

In response to an AUC information request, Apex acknowledged that gas commodity charges were flow-through amounts on a bill that were driven by the natural gas market and are beyond the control of Apex or the AUC. Apex pointed to the complexity attendant to arriving at a reasonable gas price forecast and stressed that customers choosing a competitive retailer may see very different gas commodity rates than those forecast by Apex. Thus, forecast gas prices are provided as a reference point only for bill comparison purposes.

Other distribution utilities had used the same commodity rate in both years that were being compared (in this case 2020 and 2021); the actual commodity charge in the 12-month period preceding the application was most commonly used for these purposes. This method allowed for approximation of the effect of proposed distribution rate changes on a total bill basis, avoiding the issues associated with developing a reasonable forecast for the coming year. Accordingly, the AUC directed Apex, in all future rate applications, to utilize this method for doing its typical customer bill impact analysis.

The AUC approved Apex's 2021 PBR rates on an interim basis, effective January 1, 2021.

Other Matters

Financial Reporting Requirements and Senior Officer Attestation

The AUC was satisfied that Apex had complied with the financial reporting requirements set out in Decision 20414-D01-2016 (Errata).

Finalizing the Going-In Rates and Associated 2018 Capital Factors

The AUC set the going-in rates for the 2018-2022 PBR plans based on a notional 2017 revenue requirement that was calculated using the actual pre-2017 costs, adjusted as required for anomalies. The resulting going-in rates and associated 2018 capital factors (K-bar and K factors) remained interim.

Apex's proposed anomaly adjustment required finalization. In Decision 25422-D01-2020, the AUC found that no additional anomaly adjustments were required to account for anomalies for the purposes of calculating Apex's going-in rates. Apex confirmed that the schedules filed as part of the 2021 annual PBR rate adjustment application included all adjustments necessary to finalize its going-in rates and associated 2018 capital factors.

The AUC was satisfied with the calculation of the adjustments and found that all related directions had been complied with. The AUC approved Apex's 2018 going-in rates and 2018 K-bar provided in this proceeding as final.

ATCO Electric Ltd. 2021 Annual Performance-Based Regulation Rate Adjustment, AUC Decision 25864-D01-2020

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2021 annual performance-based regulation ("PBR") rate adjustment filing from ATCO Electric Ltd. ("AE"). The AUC approved the 2021 options and riders, the 2021 system access service ("SAS") rates and the customer terms and conditions ("T&Cs") for electric distribution service. The AUC further approved the stand-alone schedules of Available Company Investment and Supplementary Service Charges. Finally, subject to the filing of post-disposition documents reflecting adjustments related to the IT common matters refunds, the AUC approved AE's 2018 going-in rates and 2018 K-bar.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor").

ATCO Electric's 2020 PBR rates were approved on an interim basis in accordance with the AUC PBR framework in Decision 24881-D01-2019.

PBR Rate Adjustments

PBR Indices and Annual Adjustments

The 2020 PBR plan for AE provided a rate-setting mechanism based on a formula that adjusted rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

AE calculated its 2021 I-X index to be 2.12 percent. The AUC approved the 2021 I factor and the resulting I-X index as calculated by AE.

(b) Y and Z factor materiality threshold

AE calculated the Y and Z materiality threshold to be $3.64 million for 2021. The AUC approved the Y and Z factor materiality threshold.

(c) Y factor

AE applied for a Y factor amount of $3.055 million. The AUC approved the Y factor as filed.

(d) Z factor

AE applied for a Z factor adjustment of negative $0.051 million in 2021 to reflect the AUC direction in Decision 25071-D01-2020. The AUC approved this adjustment as filed.

(e) Q Value

The AUC was satisfied with AE's provided calculations and approved the 2021 Q value of -4.71 percent. AE was directed to continue providing Q value calculations in future PBR rate adjustment filings

(f) K-bar factor

AE applied for a 2021 K-bar funding amount of $60.8 million. As well, AE's 2018, 2019 and 2020 interim K-bar adjustments resulted in a collection of $0.2 million for 2018, and refunds of $0.8 million for 2019, and $1.0 million for 2020.

Given findings related to IT common matters refunds, the AUC approved AE's 2021 K-bar and prior year K-bar true-ups, subject to the filing of post-disposition documents as directed with relation to distribution rates.

(g) K Factor for Type 1 Capital

AE did not apply for Type 1 capital funding for 2021.

(h) Carrying Costs

In response to an AUC information request, AE updated its calculation of carrying charges related to its Y factor, 2018 and 2019 base revenue true-ups, 2018 and 2019 K-bar true-ups and a Z factor true-up, and proposed a carrying cost collection of $0.029 million. The AUC was satisfied with the calculations but noted that the carrying costs could be affected by the AUC directions related to IT common matters refunds.

(i) Forecast Billing Determinants and Variance Analysis

AE provided detailed 2021 billing determinant forecasts. AE submitted that its forecasted 2021 billing determinants were based on the same methodology approved in Decision 24881-D01-2019. The billing determinant forecast was approved as applied for.

<u>2021 PBR Rates</u>

Distribution Rates

The AUC approved AE's calculations of its 2021 PBR rates, subject to its directions regarding the recalculation of the IT common matters refunds and the use of revised carrying charges on IT common matters refunds. Because of Decision 26170-D01-2020, the AUC noted that these rates would not be charged to customers effective January 1, 2021.

System Access Service Rates

AE indicated that its proposed 2021 SAS rates reflected the rates approved in the AESO 2020 Independent System Operator tariff, approved in Decision 25175-D02-2020. As a result, the SAS payments forecast for distribution-connected customers increased from the $322.0 million included in 2020 PBR rates, to $350.5 million for 2021. The AUC reviewed the calculations and approved the 2021 SAS rates as filed.

Rider E - Facilities Charge Agreements

As previously directed by the AUC, AE confirmed that it had removed Rider E from the price schedules in Appendix G filed with this application as it no longer formed part of AE's regulated service offering.

<u>Other Matters</u>

IT Common Matters Refunds

AE had calculated its capital adjustments for rebasing purposes related to the IT common matters placeholder using a four-year average to determine the adjustment to the notional 2017 revenue requirement. The AUC found that these amounts should have been averaged across the years 2015 and 2016 because the IT master services agreements ("MSA") had not been in effect in 2013 and 2014. The AUC found that using a two-year average better aligned with the AUC's findings in the IT Common Matters Decision. AE was therefore directed to recalculate its 2017 notional revenue requirement, K-bar and 2021 PBR rates to reflect the use of a two-year (2015 and 2016) average of its capital adjustments related to the IT common matters refunds.

The AUC approved AE's IT common matters refund adjustments directed in this decision as final, subject to the filing of post-disposition documents directed with regards to distribution rates.

Carrying Costs on IT Common Matters Refunds

The AUC did not agree with AE's argument that WACC should be used for capital and Rule 023 for O&M. The IT common matters refunds resulted from both O&M and capital; consequently, the use of WACC on both capital and O&M amounts to determine carrying costs would not be unreasonable in the circumstances.

The AUC directed AE to reflect carrying costs on IT common matters refunds using WACC for both the capital and O&M refunds in the filing of post-disposition documents as directed with regards to distribution rates.

Terms and Conditions of Service

The AUC denied the proposed revisions to Section 14.1.1(d) of the customer T&Cs. The AUC stated that the proposed change in wording, which shifted a required permanent disconnection to a discretionary disconnection after 12 months, did not add clarity for customers in determining when their service connection would be considered permanently disconnected. The AUC and AE's customers should expect that a permanent disconnection would not occur if the customer was paying idle service charges and without consultation with that customer. This was adequately addressed in Section 14.1.3(a). The AUC revised the clean version of the customer T&Cs provided by AE to reflect its denial of AE's proposed revisions to Section 14.1.1(d).

The AUC approved AE's customer T&Cs, Schedule of Available Company Investment, and Schedule of Supplementary Service Charges, as set out in an appendix to the decision.

Financial Reporting Requirements and Senior Officer Attestation

The AUC was satisfied that AE had complied with the financial reporting requirements.

Finalizing the Going-In Rates and Associated 2018 Capital Factors

The AUC set the going-in rates for the 2018-2022 PBR plans based on a notional 2017 revenue requirement that was calculated using the actual pre-2017 costs, adjusted as required for anomalies. The resulting 2018 going-in rates and associated 2018 capital factors (K-bar and K factors) were interim because they contained certain items that were either placeholders or subject to review and variance proceedings.

AE updated its interim notional 2017 revenue requirement and its 2018 base K-bar amount to reflect the 2017 net rate base adjustment related to its 2016 Regional Municipality of Wood Buffalo Wildfire Z factor in accordance with Decision 25071-D01-2020.

The AUC approved AE's going-in rates and 2018 capital factor, K-bar, provided in this proceeding, as final, subject to the filing of post-disposition documents reflecting adjustments related to the IT common matters refunds decision.

***ATCO Electric Ltd - Decision on 2021 Interim Transmission Facility Tariff,* AUC Decision 26083-D01-2020**
Interim Revenue Requirement

In this decision, the AUC approved ATCO Electric Ltd.("AEL")'s annual interim facility owner tariff based on a continuation of its approved 2020 interim tariff in the amount of $691,900,000 ($57,658,333 per month) effective January 1, 2021, and continuing until otherwise directed by the AUC.

<u>Background</u>

AEL filed an application with the AUC, requesting interim approval of its forecast 2021 transmission facility owner ("TFO") tariff, effective January 1, 2021. AEL requested approval of the interim tariff based on its forecast 2021 tariff of $718.8 million, resulting in an interim tariff of $59.9 million monthly.

In its 2020-2022 transmission general tariff application ("GTA") AEL sought approval of its forecast revenue requirements for 2020, 2021 and 2022, in the annual amounts of $724.2 million, $718.8 million and $732.2 million, respectively.

As the GTA is in the record-development stage, a final 2021 tariff will not be in place before January 2021. A decision on the GTA will likely be issued in the first quarter of 2021, and AEL's final rates will be subject to any compliance filing directed in that decision.

<u>Findings</u>

In evaluating interim rate applications, the AUC has consistently applied a two-part test. The first part of the test considers factors related to quantum and need, as applied to the specifics of the requested rate increase.

If all or a portion of the suggested rate increase appears warranted after a consideration of the quantum and need factors, the second part of the test is considered. This involves a consideration of certain general public interest factors to see if a rate increase is justified.

AEL proposes an interim tariff based on 100 percent of its forecast 2021 revenue shortfall, resulting in an increase of $26.9 million, on an annual basis, relative to the 2020 interim tariff approved by the AUC.

In the AUC's view, the proposed increase in the recovery of depreciation is a contentious item in the GTA. As such, the AUC found that a significant portion of the requested interim tariff increase is related to contentious items. The AUC therefore found AEL's forecast costs for 2021 to be insufficient to justify the proposed interim rate increase in full.

The AUC did, however, recognize that AEL has collected tariffs on an interim basis for 2018, 2019 and 2020 at levels below its respective applied-for tariffs. In the interest of promoting rate stability and easing rate shock, the AUC considers that a portion of the suggested rate increase appears warranted.

With respect to the years 2018 and 2019, the AUC noted that the amounts referenced by AEL for the currently applied-for 2018 and 2019 tariffs in the GTA are yet to be finalized. Nonetheless, based on the applied-for final tariffs, a true-up of $22.6 million for the two years combined would be expected to occur in 2021.

With respect to the year 2020, approximately $30.7 million of the requested $45.9 million 2020 interim tariff increase was related to depreciation expense.

After considering the submissions filed by AEL and the Consumers' Coalition of Alberta, the AUC was not persuaded that approval of the requested interim rate increase, in full, is in the public interest at this time, given that determinations on the contentious items in the GTA remain uncertain. The AUC denied the requested increase and found that it is just and reasonable that AEL's 2021 interim rates be based on a continuation of AEL's approved 2020 interim tariff in the amount of $691.9 million. This represents 96.3 percent of the 2021 interim tariff proposed by AEL, which will assist to smooth out any potential increase in rates for 2021 and reduce potential rate shock to ratepayers at the time the 2018 to 2021 interim tariffs are trued up.

Accordingly, the AUC approves an interim monthly TFO tariff of $57,658,333 effective January 1, 2021. The interim tariff will remain in effect until the AUC approves either a new interim tariff or a final TFO tariff.

***ATCO Gas and Pipelines Ltd. 2021 Annual Performance-Based Regulation Rate Adjustment*, AUC Decision 25863-D01-2020**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2021 annual performance-based regulation ("PBR") rate adjustment filing from ATCO Gas and Pipelines Ltd. ("ATCO"). Customer and retailer terms and conditions ("T&Cs") were approved; ATCO's 2017 capital tracker actual K factors and updated depreciation parameters were approved as final; and ATCO Gas's 2018 going-in rates and 2018 K-bar were approved as final, subject to the filing of post-disposition documents reflecting adjustments related to the IT common matters refunds as directed by the AUC

<u>Background</u>

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor").

In Decision 24881-D01-2019, ATCO's 2020 PBR rates were approved on an interim basis in accordance with the framework established by the AUC in Decision 20414-D01-2016 (Errata).

<u>PBR Rate Adjustments</u>

PBR Indices and Annual Adjustments

The 2020 PBR plan for ATCO provided a rate-setting mechanism based on a formula that adjusted rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

ATCO calculated a 2021 I-X index of 2.12 percent. The AUC approved the 2021 I factor and the resulting I-X index.

(b) Y and Z factor materiality threshold

ATCO calculated the Y and Z materiality threshold to be $2.10 million for ATCO Gas North and $1.76 million for ATCO Gas South in 2021. The AUC approved the Y and Z factor materiality threshold.

(c) Y factor

ATCO applied for Y factor amount of $6.4 million (excluding the "Other Proceeding Adjustments" item of ($9.31) million), inclusive of carrying costs. The applied-for Y factor amount was approved.

(d) Z factor

ATCO did not apply for any Z factor adjustment in 2021.

(e) Q Value

The AUC approved ATCO's 2021 Q of 0.62 percent for ATCO Gas North and 0.99 percent for ATCO Gas South.

(f) K-bar factor

ATCO applied for the 2021 K-bar funding of $57.8 million for ATCO Gas North and 59.5 million for ATCO Gas South, calculated as its 2021 required K-bar and the 2019-2020 K-bar true-up.

The AUC approved ATCO's 2021 K-bar true-ups for each of North and South, subject to the filing of post-disposition documents as directed with regards to the 2021 PBR rates.

(g) K Factor

ATCO did not apply for any Type 1 capital funding.

<u>Forecast Billing Determinants and Variance Analysis</u>

In the application, ATCO reconciled forecast and actual billing determinants from 2019. There were variances larger than ± five percent for the irrigation rate class which had an increase in average customers of 11.16 percent than was forecast. In response to previous AUC direction, ATCO explained that this variance was due to a higher number of active customers than forecast. The AUC found that ATCO's methodology and the resulting 2021 forecast billing determinants were reasonable and approved them as filed.

2017 Capital Tracker Compliance Filing True-up

The AUC found that ATCO had complied with all directions from Decision 24333-D01-2019 and approved ATCO's true-up of its 2017 capital trackers and the resulting 2017 actual K factor on a final basis.

<u>2021 PBR Rates</u>

The AUC approved the 2021 PBR rates calculated by ATCO. This approval was made subject to adjustments directed with regards to recalculating the IT common matters refund, using revised carrying charges on IT common matters refunds, and removing the proposed rate mitigation measures related to depreciation. ATCO was directed to file its 2021 PBR rate schedules reflecting the findings in this decision as post-disposition documentation in this proceeding, by January 21, 2021. The AUC noted that because of Decision 26170-D01-2020, these rates would not be charged to customers effective January 1, 2021.

Other Matters

IT Common Matters Refund

In its 2020 annual PBR rates adjustment application, ATCO updated its notional 2017 revenue requirement and its 2018 base K-bar amounts to reflect certain adjustments related to the IT Common Matters Decision, which considered whether to approve the prices contained in the IT Master Services Agreements (“MSAs”) between the ATCO Utilities (ATCO Gas and Pipelines Ltd., and ATCO Electric Ltd.) and Wipro Solutions Canada Limited. Accordingly, ATCO calculated the IT common matters-related adjustments to its notional 2017 revenue requirement and its 2018 base K-bar. It calculated a refund of $10.325 million that remained interim pending the finalization of related compliance filings. ATCO stated in this proceeding that no adjustments were required to the refund amounts.

ATCO was directed to recalculate its 2017 notional revenue requirement, K-bar and 2021 PBR rates, reflecting the use of a two-year (2015 and 2016) average of its capital adjustment related to the IT common matter refunds. The AUC was satisfied with ATCO’s true-up calculations but found that an adjustment was required from what had been filed in Proceeding 24880 for PBR rebasing purposes. ATCO’s IT common matters refund adjustments were approved, subject to the direction regarding the filing of post-disposition documents related to 2021 PBR rates.

Carrying Costs on IT Common Matters Refunds

The AUC disagreed with ATCO’s argument that WACC should be used for capital and Rule 023 for O&M. The IT common matters refunds resulted from both O&M and capital. Therefore, the use of WACC on both capital and O&M amounts to determine carrying costs would not be unreasonable in the circumstances.

The AUC directed ATCO to reflect carrying costs on IT common matters refunds using WACC for both the capital and O&M refunds in the filing of post-disposition documents as directed with regards to 2021 PBR rates.

Depreciation Study Implementation

To comply with AUC directions, ATCO included revised schedules of depreciation parameters and rates resulting from Decision 24188-D02-2020. ATCO also updated its 2018-2022 interim K-bar amounts to reflect the impact of the updated depreciation parameters.

The AUC approved ATCO’s updated depreciation parameters on a final basis and found that ATCO had complied with directions from Decision 24188-D02-2020. The AUC directed ATCO to, in the filing of post-disposition documents, recalculate its 2021 PBR rates to reflect the implementation of the approved depreciation parameters, net of Rider S, in 2021.

Terms and Conditions of Service

The AUC found that ATCO had complied with a direction from Decision 24880-D01-2019, and approved changes to the T&Cs as proposed by ATCO.

Financial Reporting Requirements and Senior Officer Attestation

The AUC was satisfied that ATCO had complied with the financial reporting requirements.

Finalizing the Going-In Rates and Associated 2018 Capital Factors

The AUC set the going-in rates for the 2018-2022 PBR plans based on a notional 2017 revenue requirement that was calculated using the actual pre-2017 costs, adjusted as required for anomalies. The resulting 2018 going-in rates and associated 2018 capital factors (K-bar and K factors) were interim because they contained certain items that were either placeholders or subject to review and variance proceedings.

ATCO confirmed that the schedules filed as part of this 2021 PBR rate adjustment application included all adjustments necessary for the purposes of finalizing its going-in rates and associated 2018 capital factors. The AUC approved ATCO's going-in rates and 2018 capital factor, K-bar, provided in this proceeding, as final, subject to the filing of post-disposition documents reflecting adjustments related to the IT common matters refunds as directed in this decision.

ATCO Gas and Pipelines 2020 GRA Phase II, AUC Decision 25428-D01-2020

Rates

In this decision, the AUC addressed Phase II of a 2020 general rate application ("GRA") filed by ATCO Gas, a distribution division of ATCO Gas and Pipelines Ltd ("ATCO Gas"). The AUC approved ATCO Gas':

(a) cost-of-service study ("COSS"), except for the request to change the currently approved methodology of allocating service costs based on cost-per-service to a methodology solely based on service length data;

(b) rate design, including the proposal to add three new rates: (i) an Ultra-High-Use delivery rate; (ii) an Alternative Technology and Appliance ("ATA") delivery rate; and (iii) a Producer Receipt Rate; and

(c) customer, retailer and producer terms and conditions of service ("T&Cs"), subject to the AUC's directions in Appendix 3 to this decision.

Cost-of-Service Study

In Decision 22394-D01-2018, the AUC directed the distribution utilities, including ATCO Gas, to base their Phase II studies "on cost data preceding 2018 and reflect any approved updated depreciation parameters." In accordance with this direction, ATCO Gas undertook for the present application the 2017 COSS based on the actual 2016 costs. This was the last year for which the AUC has reviewed and approved ATCO Gas's actual costs.

ATCO Gas Proposals

The AUC approved ATCO Gas' proposal to remove the transmission function from its COSS given its annual recovery through Rider T.

The AUC found ATCO Gas' proposal to update its space study to recognize that certain offices and warehouses house centralized groups that serve all of ATCO Gas' customers reasonable. The AUC, approved ATCO Gas' proposed changes to its functionalization step using the results of the updated space study.

The AUC found ATCO Gas' proposal to be reasonable as it provides its irrigation customers more flexibility to pump water outside the irrigation season, reduces the field work to turn on and off service, and also would not impact the amount of costs allocated to ATCO Gas' irrigation customers. The AUC approved ATCO Gas' proposed changes to the irrigation customer cost allocation methodology.

The AUC found it premature to change the currently approved methodology of allocating service costs based on cost per service to being solely based on service length data, as there may be other factors to consider, such as service size. The AUC directed ATCO Gas, in the compliance filing to this decision, to revert to the currently approved cost-per-service methodology. Further, the AUC directed ATCO Gas to, in its next Phase II application, incorporate of service size and any other relevant factors in its Phase II study.

The AUC noted InterGroup Consultants Ltd.'s concerns with the increased replacement cost for the T00320/T00248 meters and accepted ATCO Gas' explanation that a calculation error resulted in an incorrect cost for ATCO Gas South meters. As a result, the AUC directed ATCO Gas in the compliance filing to this decision to update the meter study to correct the discovered error in the data.

Rate Design

ATCO Gas stated that, consistent with previous applications, its rate design proposal incorporated accepted rate design principles commonly used for utility ratemaking purposes. These principles are sometimes conflicting, and a balance must be achieved to obtain a fair and acceptable rate design for the utility's customers.

Revenue-to-cost Ratios

The AUC found that changes proposed by ATCO Gas in its application were consistent with the AUC's long-standing desire to have each rate group's revenue-to-cost ratio at 100 percent, except in the event that other considerations, principally rate shock, temporarily prevent one or more rate group's revenue-to-cost ratios from being 100 percent. Based on ATCO Gas' analysis demonstrating rate changes from a decrease of 1.9 percent to an increase of 2.5 percent for various rate groups, the AUC agreed that rate changes arising from this application, in isolation, are unlikely to cause rate shock.

Rate Design Changes Proposed by Parties

Several changes to the currently approved rate design were proposed by ATCO Gas in its application, as well as by the Office of the Utilities Consumer Advocate ("UCA") and the City of Calgary ("Calgary") in their submissions.

1. ATCO Gas Proposal to Increase the Amount of Customer-Related Charges Collected Through the Fixed Charge for the Mid-Use Rate Group

The AUC accepted ATCO Gas' reasons for the proposed increase in the amount of Mid-Use Rate group customer-related costs collected through the fixed charge, and approved the increase with the proposed limitations in the current application of 40 percent and 60 percent in the North and South, respectively.

2. ATCO Gas Proposals for Changes to the High-Use Rate Group

ATCO Gas proposed to divide the existing High-Use Rate group into two rate groups (a new High-Use Rate group and an Ultra-High-Use Rate group). It proposed to modify the language in the High-Use Rate schedule to remove the requirement for customer consent prior to switching customers out of the High-Use Rate group, and to implement a minimum billing demand for the new High-Use Rate group and the Ultra-High-Use Rate group.

The AUC noted the small expected bill impacts associated with the proposal to divide the existing High-Use Rate group into two new High-Use Rate groups, and was of the view that cost causation is an important rate design principle that should be reflected in rates to the extent practicable, while balancing other relevant rate design principles. Accordingly, the AUC approved the division of the existing High-Use Rate group into the suggested two groups. In its compliance filing to this decision, ATCO Gas was directed to reflect the two new rate groups and associated calculations.

The AUC found the proposal to introduce minimum billing demands and the supporting explanation to constitute sound rate design. The AUC accepted the logic provided by ATCO Gas with respect to the need to modify the language used in the rate schedules regarding customers switching from the High-Use Rate group to a rate group intended for customers that consume less than 8,000 GJ/year.

3. UCA Proposal to Address Lack of Homogeneity in the Low-Use Rate Group by Splitting the Rate Group or Revising Cost Allocations

The AUC considered that dividing the Low-Use Rate group, as suggested by the UCA along residential and commercial class lines, appeared to be reasonable, but did not rule out divisions based on another basis at the time.

The AUC directed ATCO Gas to perform a full assessment of the splitting of the Low-Use Rate group, including identification of all the resulting impacts to all rate groups. The results of the assessment and any recommendations should be shared with and fully vetted by all potential stakeholders. The assessment, and the method and results of the consultation with affected rate groups and other interested parties was to be included in ATCO Gas' next

Phase II application. ATCO Gas was also directed to include a cost estimate to implement the rate group split and any costs to monitor and maintain the two new rate groups on a go-forward basis.

4. ATCO Gas Proposal for a New Rate Group – ATA Delivery Service Rate Group

While ATCO Gas indicated the ATA delivery service rate was designed on Low-Use cost methodologies accepted by the AUC and modified to meet the needs of ATA customers, several factors may impact rate design in future Phase II applications. The AUC agreed that ATCO Gas could not understand the impact of this rate until it implemented it and collected data from ATA delivery service customers. The AUC also accepted ATCO Gas' request to escalate 2020 notional rates by I-X, since there is potential for the ATA rate to vary significantly year-over-year due to the variations in billing determinants, given the expected small number of ATA customers. Escalation by I-X would provide for more stable customer rates.

The AUC approved ATCO Gas' proposal to implement the ATA delivery service rate on a pilot basis. ATCO Gas was directed to provide a detailed analysis of the ATA delivery service rate as part of its annual PBR rates adjustment filing one year following the implementation, and in its next Phase II application.

5. ATCO Gas Proposal for a New Rate Group – Producer Receipt Rate Group

The AUC approved the Producer Receipt Rate to be included in ATCO Gas' price schedules, on a pilot basis. ATCO Gas was directed to 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. This analysis should first be provided as part of its annual PBR rates adjustment filing one year following the Producer Receipt Rate implementation, and then in its next Phase II application.

6. Emergency Delivery Service

ATCO Gas proposed to discontinue this rate group, explaining that it was originally made available as a backup rate in the event of a retailer failure to supply gas, but no customers had used the rate to date and there was no anticipated future need. The AUC accepted ATCO Gas' proposal and directed that ATCO Gas implement the change in its rate design and rates.

7. Unmetered Gas Light Service

The AUC accepted ATCO Gas' reasons for its proposal to close the Unmetered Gas Light Service Rate group to new customers and to continue to provide the existing unmetered gas light customers with this service until their gas light connections reached the end of their service lives. The proposal was approved and ATCO Gas was directed to implement the change in its terms and conditions of service.

Implementation and Effective Date of Restructured Rates

The AUC directed ATCO Gas to file a compliance filing by February 1, 2021, reflecting the findings, directions and conclusions of this decision. Following finalization of ATCO Gas' 2020 Phase II methodologies in the compliance filing, implementation of the revised rate design and correspondingly updated PBR rates could take place as part of ATCO Gas' next annual PBR rate adjustment filing.

However, in the event the volatility effect of the approved Phase II revenue per customer and corresponding rates was minimal and ATCO Gas is in a position to apply the findings of this decision in the course of 2021, implementation of the new rate structure could take place as part of the proceeding dealing with the implementation of ATCO Gas' 2021 PBR rates, deferred as a result of Decision 26170-D01-2020.

Customer, Retailer and Producer T&Cs

ATCO Gas proposed certain changes to its customer and retailer T&Cs. The AUC was satisfied with the revisions made. ATCO Gas was directed to finalize its customer, retailer and producer T&Cs, as provided in this decision and in Appendix 2, as part of its compliance filing to this decision.

***ATCO Pipelines 2021 Interim Revenue Requirement,* AUC Decision 26031-D01-2020**
Rates - Interim Rate Applications

In this decision, the AUC considered an application filed by ATCO Pipelines ("AP") requesting approval of its 2021 interim revenue requirement and its Pioneer Pipeline interim revenue requirement. The AUC found AP's request to implement the Pioneer Pipeline revenue requirement on an interim basis to have been premature and found that AP's approved 2021 interim revenue requirement should be set based on a continuation of its approved 2020 revenue requirement in the amount of $307,199,000 (before the removal of forecast franchise taxes).

Introduction

On October 30, 2020, AP requested approval of its 2021 interim revenue requirement in the amount of $316,943,000 on an interim refundable basis, effective January 1, 2021. The 2021 interim revenue requirement would be recovered from NOVA Gas Transmission Ltd. ("NGTL") by way of a monthly rate of $26,140,667, after the removal of forecast franchise taxes recovered through Rider A.

On November 4, 2020, AP revised its application, requesting approval to implement, on an interim basis, the Pioneer Pipeline revenue requirement of $10,174,000, subject to AUC approval of AP's acquisition application in Proceeding 25937 (the "Facilities Application") and effective upon closing of the pipeline acquisition transaction.

Background and Details of the Application

AP filed its 2021-2023 general rate application ("GRA") with the AUC on June 16, 2020, requesting approval of a forecast 2021 revenue requirement in the amount of $316,943,000, which is the same amount as AP's applied-for 2021 interim revenue requirement. AP submitted that it did not expect a decision on its 2021-2023 GRA to be issued by the Commission before January 1, 2021.

AP's 2020 revenue requirement of $307,199,000 was approved by the AUC in Decision 25789-D01-2020. AP stated that the 2021 interim revenue requirement represents a 3.2 percent increase (or a $9,744,000 increase) over its approved 2020 revenue requirement.

In addition to its 2021 interim revenue requirement of $316,943,000, AP requested approval to implement, on an interim basis, the after-tax Pioneer Pipeline revenue requirement in the amount of $10,174,000, noting that the collection would commence only after AUC approval of the Facilities Application and upon closing of the acquisition transaction. The interim revenue requirement for the Pioneer Pipeline alone is a 3.3 percent increase over the 2020 revenue requirement. AP further indicated that it would transfer a 29.9 kilometre (km) segment of the Pioneer Pipeline located in the NGTL footprint to NGTL, and that it would also reduce the Pioneer Pipeline revenue requirement after the disposition is completed.

AP submitted that its 2021 interim revenue requirement application meets both quantum and need criteria and is in the public interest, noting that the quantum and need were driven by assets put in service in 2020 for the Pembina Keephills Transmission Pipeline Project, and other projects. It asserted that there is a large degree of certainty as to the quantum of revenue deficiency associated with the Pioneer Pipeline.

AP further submitted that the integration of the Pioneer Pipeline into the Alberta system is expected to lower the aggregate full-path system toll and have positive toll impacts for Alberta system shippers, as advised by NGTL in the Facilities Application.

AUC Findings

AP's request to implement the Pioneer Pipeline revenue requirement on an interim basis and effective upon closing of the acquisition transaction was found to have been premature. The Facilities Application and related regulatory approvals for the Pioneer Pipeline acquisition were outstanding and interveners and the AUC had filed numerous information requests in that proceeding. AER Approvals with respect to the Pioneer Pipeline were also required.

Consequently, the AUC found that approval of the acquisition of the Pioneer Pipeline as well as the timing of the interim Pioneer Pipeline revenue requirement collection were uncertain. It further noted that AP has identified that its applied-for revenue requirement of $10,174,000 associated with the Pioneer Pipeline was not final because a portion of this revenue requirement was to be reduced in accordance with the subsequent transfer of the 29.9 km pipeline segment to NGTL at the time of disposition of the segment. The final Pioneer Pipeline revenue requirement amount was not provided in the application. The AUC noted that the findings in this decision did not preclude AP from applying for an interim revenue requirement increase at a later date.

Concerning the requested 2021 interim revenue requirement, when evaluating interim rate applications, the AUC noted that it had consistently applied the two-part test established by its predecessor, the Alberta Energy and Utilities Board, in Decision 2005-099. The first part of the test relates to quantum and need factors, and includes the following considerations:

(a) The identified revenue deficiency should be probable and material;

(b) All or some portion of any contentious items may be excluded from the amount collected;

(c) Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?

(d) Can the applicant continue safe utility operations without the interim adjustment?

Where a requested rate increase appears warranted, the AUC would consider the second, public interest related part of the test, which includes the following considerations:

(a) Interim rates should promote rate stability and ease rate shock;

(b) Interim adjustments should help to maintain intergenerational equity;

(c) Can interim rate increases be avoided through the use of carrying costs?

(d) Interim rate increases may be required to provide appropriate price signals to customers; and

(e) It may be appropriate to apply the interim rider on an across-the-board basis.

The AUC acknowledged AP's arguments as to the probability of its forecasted revenue shortfall for 2021. However, AP's applied-for 2021 revenue requirement had not yet been decided in AP's 2021-2023 GRA proceeding. The AUC noted that approval of 100 percent of AP's revenue requirement was uncertain. In recognition of the uncertainty that exists at the time of any interim tariff application, concerning the ultimate disposition of the related GRA and any contentious items, the AUC has historically approved only a portion of a requested interim rate increase; typically falling within a range of 50 to 75 percent of the requested amount.

The AUC also found that AP did not demonstrate that the forecast revenue shortfall was material. AP identified that its 2021 interim revenue requirement represents a 3.2 percent increase (or a $9,744,000 increase) over its approved 2020 revenue requirement. The AUC further found that AP did not persuasively explain or otherwise demonstrate that the requested increase was necessary to preserve its financial integrity, avoid financial hardship or continue to provide safe utility operations.

The AUC found that part one of the test had not been met. The AUC was not satisfied that the AP's requested increase was warranted. The AUC denied the requested increase and found that AP's 2021 interim revenue requirement should be set based on a continuation of AP's approved 2020 interim revenue requirement in the amount of $307,199,000 (before the removal of forecast franchise taxes), which resulted in a $303,944,000 revenue requirement after the removal of forecast franchise taxes. The AUC approved an interim monthly rate of $25,328,667,32 effective January 1, 2021. The interim revenue requirement approval was to remain in effect until it was varied through approval of a new interim revenue requirement or a final revenue requirement for 2021.

BER Hand Hills Wind GP Inc. - Amendment to the Hand Hills Wind Project, **AUC Decision 22843-D04-2020**
Facilities - Wind Power Project

In this decision, the AUC approved an application from BER Hand Hills Wind GP Inc. ("BER Hand Hills") for amendments to a previously approved but not yet constructed wind power project designated as the Hand Hills Wind Project.

Application and Interveners

BER Hand Hills, pursuant to Approval 22843-D02-2018 and Permit and Licence 22843-D03-2018, has approval to construct and operate the Hand Hills Wind Power Plant and the Highland 572S Substation (collectively, the "Hand Hills Wind Project" or the "Project") in the Delia, Alberta area.

BER Hand Hills applied to the AUC for approval to amend the turbine technology, as well as the number and locations of turbines, used for the project. Specifically, BER Hand Hills sought to construct 29 Siemens-Gamesa 4.5-145 wind turbines each with a capability of 4.5 megawatts (MW) for a total capability of 130 MW. BER Hand Hills also requested approval to amend certain specifications of the substation.

The AUC provided notice of the application and received statements of intent to participate from a number of landowners who coordinated their participation in the proceeding as the Hand Hills Landowner Group ("HHLG"). The HHLG requested that the AUC deny the application or alternatively impose a number of conditions on the amended project.

Background and Amendment Application Details

The Hand Hills Wind Project was originally approved in 2012. Ownership of the Project was later transferred from Joss Wind Power Inc. to 1712610 Alberta Ltd. ("BluEarth"). The power plant was previously approved to consist of 34 Siemens SWT-2.3-101, 2.3-MW wind turbines. BluEarth filed an amendment application in 2017 but transferred ownership of the project to BER Hand Hills in 2018. BER Hand Hills updated the amendment application on numerous occasions, with the last update being filed in April 2020. The project would be located on private land in Starland County and Special Areas No. 2 near Delia, Alberta.

BER Hand Hills stated that the majority of the proposed wind turbines would be within 50 metres of the approved turbine locations. During the hearing, BER Hand Hills indicated that the interconnection was presently in Stage 2 of the AESO's interconnection process and that it was anticipated that the AUC would receive the interconnection application in mid-2021. BER Hand Hills requested that the AUC approve a December 31, 2022, construction completion date for the Project with an anticipated construction commencement date of April 1, 2022.

Interveners

Members of the HHLG own land and reside in proximity to the Project. The HHLG submitted that the amendment is not in the public interest when assessed against the adverse impacts. The HHLG identified impacts of the Project, including residential and social impacts, noise sound and vibration impacts, human and animal health impacts, environmental impacts, project construction, operation and reclamation impacts and property value impacts.

AUC's Consideration of the Application

The AUC noted that in applications such as this one, where the applicant seeks to amend its previously approved project, the AUC's public interest consideration focuses on the incremental effects associated with the proposed amendments. An amendment application does not re-open consideration of the project as a whole. Accordingly, in this proceeding, the AUC noted that it must consider any incremental effects resulting from the change in turbine model and locations, and corresponding changes to the project layout, collector system and access roads, as well as changes to the substation.

Environmental Impacts

The AUC noted that the parties expressed differing views about which linear project infrastructure, including collector lines and access roads, should be considered by the AUC in determining whether the project, as amended, is in the public interest. BER Hand Hills submitted that only those pieces of amended project infrastructure, or changes to approved project infrastructure, which result in increased negative impacts should be considered by the AUC in making a determination on the amendment application.

The AUC maintained its view that an amendment application is not an opportunity to re-visit an existing approval. However, where an applicant pursues changes to a project that require an amendment application to be filed, the AUC must assess the amended project in its entirety, to determine how its impacts compare to those of the approved project. In any electric facility project, infrastructure siting choices are made to balance a variety of competing interests. The fact that approved infrastructure is relocated in a manner that reduces or minimizes its impacts to native grassland does not exempt the relocated infrastructure from a fulsome consideration of its impacts on other components of the environment. Accordingly, the AUC did not exclude any project infrastructure from its consideration of this application.

The AUC agreed with the HHLG expert that certain standards of the *Wildlife Directive for Alberta Wind Energy Projects* ("*Directive*") are intended to be met. However, the AUC accepted that the *Directive* allows for deviations in limited circumstances, in consultation with Alberta Environment and Parks ("AEP"). In this case, AEP was aware of the setbacks for sharp-tailed grouse leks and specific wetlands being infringed upon and was presented with additional mitigation measures. The AUC put significant weight on AEP's overall assessment of the amended project which was considered moderate. As such, the AUC was not persuaded that the amendment application should be denied outright on the basis of non-adherence to *Directive* standards, as long as the reasons for non-compliance are justified and the resulting impacts to the environment can be mitigated to an acceptable degree.

The AUC accepted that BER Hand Hills endeavoured to site infrastructure to minimize environmental impacts to the greatest extent possible. Nevertheless, the AUC noted that the amended project poses a high risk to sharp-tailed grouse given the amount of disturbance within three active lek setbacks. The AUC accepted the evidence of the HHLG expert that lek attendance is not necessarily limited to lekking season or specific hours. The AUC considered that, given the outstanding high risk to sharp-tailed grouse, it was reasonable to require mitigation beyond what BER Hand Hills proposed. Consequently, the AUC imposed an additional condition of approval to protect active leks.

Although the amendment reduced the number of turbines proposed on native grassland, the AUC noted that it expects BER Hand Hills to continue to look for opportunities to further minimize impacts during construction and operation.

Finally, the AUC noted that Rule 033: *Post-approval Monitoring Requirements for Wind and Solar Power Plants* ("Rule 033") came into force on July 1, 2019, and applies to all wind projects approved after September 1, 2019. Accordingly, BER Hand Hills must comply with the requirements of Rule 033, and the AUC imposed this as a condition.

Noise Impacts

The AUC noted that in Decision 22736-D01-2020 for the Lanfine Wind Project, the AUC accepted a ground attenuation factor of 0.7 for a project area that had a relatively small percent of the project area classified as reflective surfaces (6.3 percent). The AUC accepted BER Hand Hills' evidence indicating that, in the current proceeding, an even smaller percent of the project area is comprised of reflective surfaces (three percent). Accordingly, for this project, the AUC accepted the predicted results based on noise modelling using a ground attenuation factor of 0.7. The AUC stressed that regardless of modelling parameters used, including the choice of ground attenuation factor, the post-construction monitoring must show actual compliance with the permissible sound levels.

The AUC implemented a condition that requires post-construction comprehensive noise studies at three receptor locations. The AUC denied an intervener request for a Class A2 adjustment (where measured ambient sound level is different than assumed ambient sound levels), finding that the Project area did not meet the definition of "pristine" as defined in Appendix 1 of Rule 012, and that there was not sufficient measured data nor compelling reasons to warrant a deviation from the use of assumed values in the Project area. In particular, the AUC noted that the project area already hosts third-party energy facilities.

Visual Impacts

The AUC accepted the HHLG argument that the taller turbines would individually have a greater visual impact than the previously approved shorter turbines and that the HHLG may be negatively impacted by the change. However, the AUC did not find the incremental visual impact to be reason enough to deny the amendment. The AUC did note that the reduction in number of turbines would be expected to decrease visual impacts where turbine locations have been removed.

The AUC noted that it expects that BER Hand Hills will implement shadow flicker mitigation as necessary on a case-by-case basis. The AUC accepted that BER Hand Hills is aware of intervener concerns regarding the visual impacts of turbine lighting, and does not intend to install turbine lighting beyond what is required by Transport Canada to ensure aircraft safety.

Property Impacts

The AUC agreed that the potential for the turbine foundations to intercept the water table was negligible, and there was no evidence to substantiate the assertion that vibrations from the turbines might otherwise impact water quality in the project area. The AUC found that the project's potential risk to groundwater and wells was low. The AUC was not persuaded there would be negative impacts to property values associated with the proposed amendment that warrant the application being conditioned or denied.

Health Impacts

While the AUC accepted that concerns about potential health impacts of the project were sincerely held, specialized expertise and evidence is required for the AUC to conclude that a project will have an adverse effect on human health. No such evidence was presented in this proceeding.

Other Impacts

To ensure that cultural and heritage impacts are effectively mitigated, the AUC will require BER Hand Hills to provide confirmation that it has obtained a *Historical Resources Act* approval prior to construction. Dust control measures must be adopted to address certain dust related issues. A project-specific conservation and reclamation plan must be filed with AEP prior to commencing construction. The AUC granted a construction completion date of December 31, 2023.

***ENMAX Energy Corporation - Decision on 2021 Interim Regulated Rate Option Non-Energy Tariff*, AUC Decision 25949-D01-2020**
Interim Rates - RRO Non-energy

In this decision the AUC approved the current regulated rate tariff non-energy rates as interim rates for ENMAX Energy Corporation ("ENMAX"), effective January 1, 2021.

AUC Findings

ENMAX requested the continuation of its final 2020 RRO non-energy rates on an interim basis beginning January 1, 2021. Because these rates were previously tested and approved by the AUC in Decision 23752-D01-2020 and Decision 25551-D01-2020, the AUC considered that ENMAX's request to continue these rates for 2021 on an interim basis was reasonable and in the public interest. These rates will be adjusted upon approval of ENMAX's final 2021 non-energy rates. The AUC therefore approved ENMAX's request for interim rates beginning January 1, 2021.

ENMAX did not file the rate schedules applicable to the interim rate request, therefore the rate schedules approved in Decision 25551-D01-2020 will continue to apply on an interim basis.

ENMAX was directed to file an application to collect or refund the difference between interim and final rates for the period during which interim rates were charged once the AUC has approved ENMAX's final 2021 RRO non-energy rates.

***ENMAX Independent Energy Solutions Inc. - Connection for the Downtown District Energy Centre Combined Heat and Power Unit*, AUC Decision 26110-D01-2020**

Connection Order

In this decision, the AUC approved an application from ENMAX Independent Energy Solutions Inc. ("EIES") for the connection of a 3.3-megawatt ("MW") natural gas-fuelled combined heat and power generating unit located at ENMAX Corporation's Downtown District Energy Centre to the Alberta Interconnected Electric System ("AIES") via ENMAX Power Corporation's 25-kilovolt distribution system.

Background

EIES owns and operates the 3.3-MW natural gas fuelled combined heat and power cogeneration system (the "Power Plant") at the ENMAX Downtown District Energy Centre in Calgary, pursuant to Approval 23243-D04-2018.

The construction and operation of the Power Plant was initially approved by the AUC in Decision 21247-D01-2016. However, the AUC deferred its decision on connecting the Power Plant to the AIES. The AUC found that an approval from ENMAX Power Corporation to connect the Power Plant to its 25-kilovolt distribution system was required, and that it would make a decision on connecting the Power Plant to the AIES when this approval was submitted to the AUC.

On November 24, 2020, EIES applied to the AUC for approval to connect the Power Plant to the AIES and included a copy of an Interconnection Agreement dated March 2, 2018, for the connection of the Power Plant to ENMAX Power Corporation's facilities through ENMAX Corporation's connection to the AIES.

On November 5, 2020, EIES, ENMAX Corporation and Calgary District Heating Inc. ("CDHI") executed a confidential Asset Purchase and Sale Agreement ("APSA"), by which CDHI agreed to purchase, and EIES and ENMAX Corporation agreed to sell, the Downtown District Energy Centre business, including the facilities and equipment associated with the Downtown District Energy Centre and the Power Plant. EIES explained that during these transactions it discovered that it had inadvertently not filed a copy of ENMAX Power Corporation's approval of the connection with the Commission as was required by Decision 21247-D01-2016, and as a result, the Commission's decision on the connection remains outstanding.

The issuance of a connection order is one of a number of closing conditions of the APSA required to effect the transfer of the Power Plant to CDHI. EIES stated that an application for an ownership transfer of the Power Plant would be filed in due course.

Commission Findings

While the AUC noted that the Power Plant was connected to the AIES via ENMAX Power Corporation's 25-kilovolt distribution system since March 2018, contrary to Section 18 of the *Hydro and Electric Energy Act*, it accepted that this was unintentional on EIES's part.

The AUC also considered that there were no objections to the Power Plant connection in the original proceeding; that the Power Plant has been connected to the AIES and operating since 2018 without complaint from stakeholders; and that the connection was made only after approval of the local distribution company was given in the signed Interconnection Agreement.

Based on the foregoing, the AUC approved the connection, finding that the project was in the public interest in accordance with Section 17 of the *Alberta Utilities Commission Act.*

ENMAX Power Corporation 2021 Annual Performance-Based Regulation Rate Adjustment, **AUC Decision 25865-D01-2020**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2021 annual performance-based regulation ("PBR") rate adjustment filing from ENMAX Power Corporation ("ENMAX"). The AUC approved the 2021 distribution service rates and corresponding rate schedules and the distribution access service ("DAS") adjustment rider in the amount of $2.47 million. The AUC approved the distribution tariff terms and conditions ("T&Cs") on an interim basis pending completion of Proceeding 25861, and ENMAX's 2018 going-in rates and 2018 K-bar were approved as final.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor").

In Decision 24875-D01-2019 ENMAX's 2020 PBR rates had been approved on an interim basis in accordance with the framework established by the AUC in Decision 20414-D01-2016 (Errata).

PBR Rate Adjustments

2021 PBR Indices and Annual Adjustments

The 2020 PBR plan for ENMAX provided a rate-setting mechanism based on a formula that adjusted rates annually through an indexing mechanism plus specifically approved adjustments.

(a) I-X index

ENMAX calculated its 2021 I-X index to be 2.12 percent. The AUC approved the 2021 I factor and the resulting I-X index.

(b) Y and Z factor materiality threshold

ENMAX calculated a Y and Z materiality threshold of $1.91 million in 2021. The AUC approved the threshold.

(c) Y factor

ENMAX applied for a Y factor amount of $1.95 million, inclusive of carrying costs. The applied-for Y factor amount was approved as filed.

(d) Z factor

ENMAX did not apply for any Z factor adjustments in 2021.

(e) Q Value

The AUC approved the applied-for 2021 Q value of -3.66 percent.

(f) K-bar factor

The AUC approved ENMAX's 2021 K-bar of $35.12 million. The 2021 K-bar was made subject to a further true-up for the 2021 actual approved cost of debt.

(g) K factor

At the time of this filing, ENMAX had two Type 1 capital placeholders, approved in Decisions 23892-D01-2019 and 24875-D01-2019, for the cost recovery of 90 percent of the management-approved internal 2019 and 2020 forecasts of capital additions in the amounts of $18.81 million and $6.38 million, respectively. These costs were associated with relocation of ENMAX's infrastructure pursuant to The City of Calgary's Green Line Light Rail Transit ("LRT") Project. The correspondingly approved incremental revenue requirement figures were $1.02 million for 2019 and $1.25 million for 2020.

ENMAX applied for approval of a 2021 revenue requirement of $1.78 million. This would represent 90 percent of the total 2021 revenue requirement of $1.97 million associated with the Green Line LRT Project.

The AUC accepted ENMAX's 2021 revenue requirement forecast in the amount of $1.97 million. By a disposition letter in Proceeding 25765, ENMAX had been granted a request to combine its 2019 and 2020 true-up applications into a single application to be filed in Q2 2021, which would consider the eligibility of this project for Type 1 capital treatment and the related true-up of actual costs. The AUC considered that the amount approved in this proceeding could also form part of the AUC's review of ENMAX's upcoming true-up application. ENMAX was directed to provide the detailed analysis of its total 2019 and 2020 capital additions of $18.81 million and the associated 2021 revenue requirement amount of $1.97 million as part of that application.

(h) Forecast Billing Determinants and Variance analysis

In Decision 23355-D02-2018, the AUC directed ENMAX to continue to provide annual and monthly forecasts of billing determinants in its future annual PBR rate adjustment filings. ENMAX indicated that its forecast was based on the same methodology approved in Decision 21508-D01-2017 and applied throughout the PBR regime. With regards to adjustments made because of the COVID-19 pandemic, ENMAX explained that in 2020 it had experienced lower than normal levels of energy consumption and demand usage for the Large Commercial Secondary – D310 (-12 percent) and Large Commercial Primary – D410 (-14.6 percent) rate classes and a higher level of energy consumption for the Residential – D100 rate class (+3.3 percent). Therefore, ENMAX adjusted forecasts for these rate classes to reflect the expected changes in energy consumption.

ENMAX reconciled forecast and actual billing determinants from 2019. There were variances larger than ± five percent for energy consumption in Medium Commercial – D300 and Street Lighting – D500 rate classes. ENMAX explained that actual commercial demand was driven lower as a result of fewer sites, with a number of customers moving to a lower rate class. Street lighting difference was attributable to fewer light fixtures, coupled with the move to light-emitting diode lights.

Based on its review and assessment of ENMAX's methodology and billing determinants in this proceeding, the AUC found that the methodology employed and the resulting 2021 forecast billing determinants were reasonable.

<u>2021 PBR Rates</u>

Distribution Rates

The AUC approved ENMAX's 2021 PBR rates effective January 1, 2021, on an interim basis, subject to finalization of ENMAX's Phase II compliance filing currently under consideration in Proceeding 25861.

DAS Adjustment Rider

ENMAX applied for approval to include a distribution access service ("DAS") adjustment rider to reconcile amounts related to a 2017 K factor true-up and a DAS adjustment rider true-up for 2019 and 2020.

ENMAX recalculated the accounting test based on the approved capital tracker amounts and, proposed to collect $2.24 million related to the 2017 K factor. ENMAX explained that a DAS adjustment rider true-up for 2019 and 2020 was required because of volume differences over the collection period. ENMAX's calculations resulted in a true-up of $0.04 million for 2019 and ($0.02) million for 2020 that ENMAX included in the 2020 DAS adjustment rider. ENMAX proposed to implement the DAS rider from January 1 to March 31, 2021, and calculated the total adjustment amount to be $2.47 million, inclusive of associated carrying costs.

The AUC approved the DAS adjustment rider in the amount of $2.47 million and the implementation of the rider adjustment over the three-month period, from January 1 to March 31, 2021. The AUC directed that, in its 2022 annual PBR rate adjustment application, or its next DAS rider application, whichever came first, ENMAX explain whether its DAS adjustment rider true-up practice to account for the differences in volume was consistent with this direction.

<u>Other Matters</u>

Hybrid Deferral Account

In Decision 24875-D01-2019, the AUC approved ENMAX's request to implement the treatment of its Alberta Electric System Operator ("AESO") contribution amounts similar to the hybrid deferral account approach approved for FortisAlberta Inc. in Decision 23505-D01-2018.

Two projects resulted in a net increase in capital additions to rate base of $5.73 million in 2019, leading to a 2019 deferral account true-up refund of $0.25 million. With respect to 2020, the costs associated with the No. 162 Substation 2nd 138-25kV Transformer Addition incurred in Q1 of 2020 resulted in a net increase in capital additions to rate base of $0.11 million in 2020. This resulted in a 2020 deferral account true-up refund of $0.38 million. The total adjustment for the AESO Contribution Hybrid Deferral Account was a refund of $0.63 million, plus associated carrying costs of $0.02 million.

The AUC approved a refund of $0.63 million and directed ENMAX to reflect any forthcoming adjustments regarding these three projects as part of its 2021 annual PBR rate adjustment filing.

Terms and Conditions of Service

The AUC noted that ENMAX comprehensively revised its customer T&Cs as part of its Phase II application in Proceeding 24820. This matter was subject to finalization and the AUC's approval in ENMAX's Phase II compliance application, currently under review in Proceeding 25861. The AUC approved ENMAX's customer T&Cs in this proceeding, on an interim basis.

Financial Reporting Requirements and Senior Officer Attestation

The AUC found that ENMAX had complied with the financial reporting requirements.

Finalizing the Going-In Rates and Associated 2018 Capital Factors

The AUC approved ENMAX's 2018 going-in rates and 2018 capital factor, K-bar, calculated in this proceeding, as final.

***EPCOR Distribution and Transmission Inc. - Decision on 2021 Customer Specific Distribution Access Service Rate Update for an Existing Customer*, AUC Decision 26120-D01-2020**

Rate Update Existing Customer

In this decision, the AUC approved an application by EPCOR Distribution & Transmission Inc. ("EPCOR") for a customer specific ("CS") distribution access service ("DAS") rate update for an existing customer of $731.54 per day, effective January 1, 2021.

Background

EPCOR filed an application requesting approval for a CS DAS rate update for an existing customer, effective January 1, 2021.The rate update was requested as the customer, currently receiving service under an existing customer rate class, requested a reduction of its peak demand due to it experiencing lower than expected peak demand.

The CS rate class is comprised of customers with annual energy demands over 5,000 kilowatts (kW). As the customer requested a reduction in peak demand, EPCOR executed the change in peak demand and contracted minimum demand as per Article 11.3 of its distribution connection service terms and conditions.

Calculation of the 2021 Existing Customer Rate

EPCOR explained that the cost-of-service calculation generally includes three components: incremental equipment and installation activities; cost of existing assets to provide service; and allocated operating, maintenance and general ("OM&G") costs.

EPCOR further explained that the customer is part of its critical urban load group, which includes critical commercial or industrial operations, large downtown core or public safety-related loads (for example, hospitals) and as such, standby service is required.

Findings

The AUC observed that the methodology used by EPCOR to calculate the existing customer rate adjustment is the same cost-of-service methodology used by EPCOR in its calculation of other CS rates. The AUC reviewed EPCOR's calculation of the proposed existing customer rate update and found it to be reasonable and consistent with the previously approved methodology.

The AUC therefore found EPCOR's proposed existing customer rate update reasonable. Accordingly, the existing customer rate of $731.54 per day, effective January 1, 2021, was approved.

Consistent with past practices, the AUC directed EPCOR to true up any differences if the actual effective date for the revised existing customer rate differs from January 1, 2021, and the rate will be trued up to reflect the 2021 actual cost of debt when it becomes available.

In approving the application for the updated existing customer rate, the AUC noted that it expressly does not authorize the recovery by EPCOR of any amount payable by the customer from other EPCOR customers in the event of default or bankruptcy of the customer. The AUC directed EPCOR to bring any such unpaid amount to its attention, at which time the AUC will determine the regulatory treatment of the outstanding amounts.

***EPCOR Distribution and Transmission Inc. 2021 Annual Performance-Based Regulation Rate Adjustment,* AUC Decision 25866-D01-2020**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2021 annual performance-based regulation ("PBR") rate adjustment filing from EPCOR Distribution & Transmission Inc. ("EPCOR"). The AUC determined that:

(a) The 2021 distribution rates, options and riders and corresponding rate schedules set out in the decision, were approved effective January 1, 2021;

(b) The 2021 system access service ("SAS") rates as filed and set out in the decision, were approved effective January 1, 2021;

(c) The distribution connection service ("DCS") terms and conditions ("T&Cs") and EPCOR's T&Cs for electric distribution access service ("DAS"), as set out in the decision, were approved effective January 1, 2021;

(d) 2021 distribution tariff policies set out in the decision were approved effective January 1, 2021; and

(e) EPCOR's 2018 going-in rates and 2018 K-bar, provided in this proceeding, were approved as final.

<u>Background</u>

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor").

EPCOR's 2020 PBR rates had been approved on an interim basis in Decision 24882-D01-2019.

<u>PBR Rate Adjustments</u>

PBR Indices and Annual Adjustments

(a) I-X Index

The AUC approved the 2021 I factor of 2.42 percent and the resulting I-X index of 2.12 percent.

(b) Y and Z Factor Materiality Threshold

EPCOR did not provide a calculation for Y and Z materiality threshold in its application. In the prior PBR rate update application, EPCOR's 2020 Y and Z factor materiality threshold was calculated as $1.72 million. By applying the 2021 I-X index of 2.12 percent to the 2020 materiality threshold, the AUC calculated EPCOR's 2021 Y and Z factor threshold as $1.76 million. EPCOR was directed to provide a Y and Z factor threshold calculation in its future annual PBR rate adjustment application.

(c) Y and Z Factors

EPCOR applied for a Y factor amount of $11.80 million, which was approved by the AUC. EPCOR did not apply for a Z factor adjustment in 2021.

(d) Q Value

The AUC reviewed EPCOR's calculations and approved the 2021 Q value of -1.06 percent. EPCOR was directed to continue providing Q value calculations in its future annual PBR rate adjustment filings.

(e) K-Bar Factor

The AUC approved EPCOR's 2021 K-bar of $30.93 million. EPCOR's 2021 K-bar will be subject to true-up for the 2021 actual approved cost of debt.

(f) K Factor

EPCOR did not apply for any Type 1 capital funding for 2021.

Forecast Billing Determinants and Prior Year Variance Analysis

EPCOR indicated that its 2021 billing determinants forecast was based on the methodology approved in Decision 24882-D01-2019 and throughout the PBR regime, except for the Direct Connect ("DC"), Customer Specific ("CS") and Customer Specific, Totalized ("CST") rate classes. To forecast its 2021 DC, CS and CST customer rate classes, EPCOR used a three-year average of energy and demand. It based its forecast on a three-year model to even out deviations in a give year.

(a) DC Customer Rate Class

The AUC found the one-year actual method of forecasting for the DC rate class to be preferable. For regulatory efficiency, the AUC did not require EPCOR to change its billing determinants forecast for the DC rate class. EPCOR was directed to address the issue of the apparent declining consumption trend and comment on the most accurate forecasting method for the DC rate class given the declining trend and customer information available, in future PBR rate adjustment filings.

(b) CST and CS Customer Groups

The AUC found EPCOR's methodology and billing determinants, to have been reasonable and approved the methodology and the resulting 2021 forecast billing determinants as filed.

(c) 2019 Billing Determinants Variance Analysis

The DC and CST rate class energy variances were the most significant of the variances at -14.7 percent and -27.8 percent and could, if the variance level remains, require increased scrutiny by the AUC in future annual rate update applications. In addition to continuing to provide information on variance from forecast to actual billing determinants by rate class and to identify the cause of variances larger than five percent, EPCOR was directed to comment on whether large variances appearing for multiple years would require a more accurate forecasting method, a change in rate structure, or both.

True-Ups for 2018 and 2019

The AUC found EPCOR's calculations and explanations of the 2018 and 2019 true-ups to have been reasonable. The AUC approved the inclusion of these true-up amounts in EPCOR's 2021 PBR rates.

<u>2021 PBR Rates</u>

Distribution Rates

The AUC found EPCOR's calculation methods of its 2021 rates to have been consistent with previously accepted methodologies during the current PBR term. The AUC approved EPCOR's 2021 PBR rates.

System Access Service Rates

EPCOR indicated that its proposed 2021 system access service (“SAS”) rates would reflect the rates approved in the Alberta Electric System Operator’s (“AESO”) 2020 Independent System Operator (“ISO”) tariff. EPCOR assumed a pool price of $55.28 per MWh and an operating reserve of 5.90 percent for 2021, based on EPCOR’s actual 2019 monthly average operating reserve percentage. The proposed 2021 SAS rates and 2021 Balancing Pool Rider G were approved.

Customer Specific Rates

(a) CS42 2020 Base Rate

The AUC approved the 2020 base rate for the CS42 customer as $1,215.44 per day on an interim basis.

(b) CS49 Rate True-Up and Base Rate

The AUC approved the CS49 true-up daily rate of $33.70 and 2021 updated daily base rate of $379.10 as calculated by EPCOR.

Other Matters

Terms and Conditions of Service

EPCOR amended its distribution terms and conditions (“T&Cs”) in accordance with the I-X mechanism. EPCOR adjusted its maximum investment levels (“MILs”) and specific customer contributions by the I-X mechanism for 2021 in its customer DCS T&Cs. The AUC reviewed and approved the revised MILs and specific customer contributions provided in Schedule A of the DCS T&Cs for 2021.

Financial Reporting Requirements and Senior Officer Attestation

The AUC was satisfied that the financial information provided by EPCOR met the financial reporting requirements.

Finalizing the Going-In Rates and Associated 2018 Capital Factors

The AUC was satisfied that EPCOR’s notional 2017 revenue requirement and 2018 capital factor schedules had been calculated correctly and were in alignment with previously issued AUC directions. The AUC approved EPCOR’s 2018 going-in rates and 2018 capital factor, K-bar, provided in this proceeding, as final.

***EPCOR Energy Alberta GP 2021 Regulated Rate Tariff Interim Rates Application*, AUC Decision 26023-D01-2020**

Rates

In this decision, the AUC approved the application from EPCOR Energy Alberta GP Inc. (“EEA”) to apply existing non-energy charges for its regulated rate tariff (“RRT”), as interim rate effective January 1, 2021.

Introduction

EEA requested approval to continue charging the 2020 non-energy charges that had been approved in Decision 24034-D01-2019 as 2021 interim non-energy RRT rates. It also requested that these rates stay effective from January 1, 2021 until the AUC approved, and EEA implemented, a final RRT for 2021 or the AUC had approved a revised 2021 interim RRT.

Particulars of the Application

The following tables show the previously approved non-energy charges on a dollars per month per site and dollars per day per site basis.

Non-Energy Charges for EDTI Service Area

Customer Class	2020 Non-Energy Charge ($/month/site)	2021 Proposed Interim Rate ($/day/site)
Residential	6.16	0.202
Small Commercial	5.59	0.184
Security Lights	5.85	0.192

Non-Energy Charges for Fortis Service Area

Customer Class	2020 Non-Energy Charge ($/month/site)	2021 Proposed Interim Rate ($/day/site)
Residential	6.30	0.207
Farm	5.71	0.188
Irrigation	3.84	0.126
Small Commercial	7.06	0.232
Oil and Gas	11.50	0.378
Lighting	6.15	0.202

AUC Findings

The AUC approved the proposed 2021 interim rates on an interim refundable basis and determined that continuing the non-energy rates from 2020 would result in regulatory efficiency and rate certainty for customers.

***FortisAlberta Inc. 2021 Annual Performance-Based Regulation Rate Adjustment,* AUC Decision 25843-D01-2020**

Rates - Performance-Based Regulation

In this decision, the AUC considered the 2021 annual performance-based regulation rate ("PBR") adjustment filing from FortisAlberta Inc. ("Fortis"). The AUC approved the 2021 distribution rates, options and riders corresponding rate schedules, the 2021 system access service ("SAS") rates and Fortis' 2018 going-in rates and 2018 K-bar. The AUC also approved the customer and retailer terms and conditions ("T&Cs") for electric distribution service and the customer contribution schedules and fee schedule. The approvals were effective as of January 1, 2021.

Background

The PBR framework approved in Decision 20414-D01-2016 (Errata) provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation ("I") that is relevant to the prices of inputs the utilities use, less a productivity offset ("X").

In Decision 20414-D01-2016 (Errata), the AUC approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly ("Y factors"), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan ("Z factor").

Fortis' 2020 PBR rates had been approved on an interim basis in Decision 24876-D01-2019.

PBR Rate Adjustments

PBR Indices and Annual Adjustments

(a) I-X Index

Fortis calculated its 2021 I-X index to be 2.12 percent. The AUC approved the 2021 I factor and I-X index as calculated by Fortis.

(b) Y and Z Factor Materiality Threshold

As Fortis did not apply for any new Y factor cost items or any Z factors, it did not calculate a Y and Z factor materiality threshold.

(c) Y and Z Factors

The AUC approved the applied for Y factor refund amount of $1.5 million. Fortis did not apply for any Z factor adjustments in 2021.

(d) Q Value

The Consumers' Coalition of Alberta ("CCA") objected to Fortis' applied for Q value of negative 2.14 percent. Given the AUC's findings regarding Fortis' billing determinant forecast, discussed below, the AUC denied Fortis' applied for Q and approved a Q of negative 1.33 percent.

(e) K-Bar Factor

Fortis applied for a 2021 K-bar funding amount of $74.3 million, calculated as its 2021 required K-bar and adjustments to 2018 through 2020 K-bar amounts inclusive of carrying costs. Adjustments to 2018 through 2020 amounts were proposed to account for the approved 2016 and 2017 Alberta Electric System Operator ("AESO") contribution capital tracker amounts, an update to the depreciation rate for AESO contributions, the actual 2019 cost of debt, and to reflect the final approved purchase price for the Crowsnest Pass and Fort Macleod distribution systems in accordance with Decisions 23961-D01-2019 and 23972-D01-2020.

The AUC took issue with Fortis' billing determinants and, accordingly denied the applied for 2021 K-bar funding amount and approved a 2021 K-bar funding amount $71.5 million. This amount would be subject to a further true up for the 2021 actual approved cost of debt.

(f) K Factor for Type 1 Capital Funding

Fortis did not apply for any Type 1 capital funding for 2021. The AUC found Fortis' calculation of its 2016 and 2017 K factor true-up amounts to have been reasonable. The 2021 K factor true-up refund amount of $1.2 million was approved.

(g) AESO Contributions Hybrid Deferral

Fortis applied for a 2021 AESO contributions hybrid deferral refund amount ("CHDRA") of $25.8 million. This amount included the calculated 2021 capital funding for AESO contributions subject to the hybrid deferral account as well as several adjustments to the 2018 through 2020 amounts.

The AUC found that Fortis had complied by the directions made in Decision 23505-D01-2018 related to the 2021 AESO CHDRA and that Fortis had made appropriate adjustments in its calculations as required. Given the findings regarding Fortis' billing determinant forecast discussed below, the AUC denied Fortis' applied for 2021 AESO CHDRA and approved a 2021 AESO CHDRA of $26.2 million.

(h) Adjustment to the Depreciation Rate for the AESO Contributions

In response to a direction in Decision 24932-D01-2020, Fortis adjusted the depreciation rate used for its AESO contributions from 3.63 to 2.56 percent. The AUC approved the applied-for adjustments to the depreciation rate for Fortis' AESO contributions

(i) Forecast Billing Determinants and Variance Analysis

Fortis provided detailed 2021 billing determinant forecasts based on the same methodology approved in Decision 24876-D01-2019, with the exception that it adjusted the forecasts to account for the impacts of the COVID-19 pandemic and coinciding low oil price environment.

The AUC found that the 2021 billing determinants were derived using the approved forecast methodologies, but with refinements to the forecast. The AUC noted that as per Decision 20414-D01-206 (Errata), no such changes to the forecasting methodology could be implemented unless otherwise ordered by the AUC.

Regarding the use of the Canadian Mortgage and Housing Corporation ("CMHC") report, Fortis replaced the bank and conference Board of Canada ("BCBC") forecasts for the Edmonton and Calgary regions with the lower CMHC forecasts. The AUC denied Fortis' proposal to adjust its forecast for the number of housing starts and corresponding billing determinants using the CMHC report.

Regarding the use of quotients to adjust the forecast for the small general service, general service, and oil and gas rate classes, the AUC accepted Fortis' calculation of the quotients based on the ratio of 2020 year-to-date actual billing determinants as temporary modifications to Fortis' approved forecasting methodologies. The AUC found that Fortis did not calculate and apply quotients for all billing determinant categories for the rate classes where the use of quotients was proposed, and further found that they should be applied consistently.

Fortis was directed to, in its next annual PBR rate application, comment on the extent to which actual billing determinants throughout the billing determinants throughout the pandemic period should inform its 2022 billing determinant forecast. Further, Fortis was to assess whether adjustments to its forecasting methodology, or the data used in the forecast, were necessary to develop forecasts that were as accurate as predictable.

While the variance for the exterior lighting rate class was significant, a new forecasting methodology had been applied for 2020 which was expected to reduce variances in the future.

<u>2021 PBR Rates</u>

Distribution Rates

Fortis provided bill impact schedules reflecting the 2021 rates that would go into effect on January 1, 2021. The AUC rejected a request from Obsidian Energy to dismiss any request for rate increases, noting that the total bill increase for a typical Rate 44/45 - Oil & Gas Service is estimated at 2.5 percent. The AUC accepted Fortis' proposal to mitigate the rate increase for the irrigation rate class to 10 percent by using the transmission adjustment rider to defer the collection of transmission-related revenue.

The AUC accepted the general principles and methodologies utilized by Fortis for calculating its 2021 PBR rates. Fortis' 2021 PBR rates were approved on an interim basis effective January 1, 2020.

System Access Service Rates

Fortis indicated that its proposed 2021 system access service ("SAS") rates reflected the rates applied for by the AESO in Proceeding 26054. The SAS payments forecast for distribution connected customers increased from the $634.458 million included in 2020 PBR rates, to $671.359 million for 2021. Fortis updated its 2021 Balancing Pool adjustment rider to align with the AESO's Rider F rate of $2.3/MWh. The AUC approved the 2021 SAS rates as filed.

Other Matters

Terms and Conditions of Service

The AUC approved Fortis' customer T&Cs, retailer T&Cs, customer contributions schedules and fee schedule.

Rate Schedule Wording Amendment for Municipal Assessment and Franchise Fee Riders

The AUC approved the applied-for wording changes made by Fortis as filed.

Financial Reporting Requirements and Senior Officer Attestation

The AUC found that Fortis complied with the financial reporting requirements, except for the ROE adjustment schedule. Fortis was directed to provide a ROE adjustment schedule for the years 2018 through 2020 as a post-disposition document in this proceeding.

Earning Carryover Mechanism Amounts in Rule 005 Reporting

The AUC found that Fortis' existing Rule 005 reports contain the necessary information to allow any party to calculate the ROEs with the ECM included if desired. The AUC therefore found there to be limited value in having Fortis refile its Rule 005 report and denied a request to include earning carryover mechanism amounts.

Finalizing the Going-In Rates and Associated 2018 Capital Factors

The AUC approved Fortis' going-in rates and 2018 capital factor, K-bar, provided in this proceeding, as final.

Name Change Order Apex Utilities Inc. from AltaGas Utilities Inc.
Name Change

AltaGas Utilities Inc., a designated regulated gas utility pursuant to the *Gas Utilities Designation Regulation* amended its articles of incorporation to change its corporate name from AltaGas Utilities Inc. to Apex Utilities Inc. The AUC ordered that as of November 6, 2020:

- all references to any AUC approvals, decisions or permits and licences in effect for AltaGas Utilities Inc. were to apply to Apex Utilities Inc. as if Apex Utilities Inc. had been the named regulated gas utility in those approvals, decisions, permits and licences;
- all AUC rules to which AltaGas Utilities Inc. was required to comply apply to Apex Utilities Inc.; and
- for any legislation over which the AUC had oversight that designated AltaGas Utilities Inc., Apex Utilities Inc. would comply with that legislation as if it had been specifically designated.

All new submissions must be filed in the name of Apex Utilities Inc.

***Salt Box Coulee Water Supply Company Ltd. - Decision on Terms and Conditions for Calling Horse Estates Co-operative Association Ltd.*, AUC Decision 25849-D01-2020**

Water Supply - Terms and Conditions

In this decision, the AUC approved Salt Box Coulee Water Supply Company Ltd.'s ("Salt Box") terms and conditions ("T&Cs") of service for Calling Horse Estates Co-operative Association Limited ("CHECAL"), effective January 1, 2021.

Background

Pursuant to directives issued by the AUC, Salt Box filed a water supply agreement dated February 1, 1994, between Salt Box, Calling Horse Estates Limited and Windmill Water Co-op Ltd. ("Windmill") and proposed T&Cs for CHECAL. In its proposed T&Cs, Salt Box requested the following:

(a) Salt Box's permission be required before adding or removing homes serviced by CHECAL;

(b) a fixed charge of $120.00 per month and a commodity charge of $5.00/m^3;

(c) a water connection charge of $500.00 or $300.00 and a water availability charge of $120.00/month for newly serviced homes;

(d) a two-year notice for termination of service;

(e) a water reconnection charge of $3,000.00; and

(f) disconnection for non-payment within 10 days.

The AUC found that the CHECAL water supply agreement filed, was the best available information for the AUC to establish T&Cs for CHECAL, and certain specific sections of the CHECAL water supply agreement should serve as the basis for Salt Box's T&Cs with CHECAL. The AUC compiled the relevant sections together with additional sections related to meter accuracy, the goods and services tax and interest, and called for comments.

Salt Box provided its comments on the compiled T&Cs stating:

(a) the Commission should ensure that CHECAL has T&Cs for its customers;

(b) a term should be added regarding disconnections with sufficient notice to Saltbox;

(c) if service was to be shut-off for non-payment, this would not occur on an individual customer basis;

(d) Saltbox cannot keep water on hold for a customer of CHECAL in the event of disconnection; and

(e) currently, CHECAL pays its invoices within 10 days and not the 30 days proposed by the Commission.

Findings

In its comments, Salt Box submitted that the AUC should ensure CHECAL has T&Cs for its customers if Saltbox does not have T&Cs directly to CHECAL's customers. The AUC found that, whilst is appreciated the need for oversight of T&Cs for utility service to end-use customers of the system, CHECAL is organized as a cooperative. The T&Cs between CHECAL and its customers are therefore not within the AUC's jurisdiction. Water cooperatives and its T&Cs are governed under the *Rural Utilities Act*, which is governed under the Minister of Alberta Agriculture and Forestry. However, the AUC has the authority to set T&Cs for Salt Box's public utility service to CHECAL pursuant to the *Public Utilities Act*, as Salt Box was declared to be a public utility under the AUC's jurisdiction. In terms of Salt Box's public utility service, CHECAL is a customer who receives distribution service directly from Salt Box. The T&Cs for distribution service provided to CHECAL is therefore appropriately decided by the AUC.

With respect to the notice required for disconnection of service, Salt Box requested that a term be added to the CHECAL T&Cs to include more notice as this was a problem Salt Box experienced in the past and CHECAL did not have the needed T&Cs to disallow its customers from disconnecting. The agreement with CHECAL was for the full group of houses to connect and not to come and go. In addition, Alberta Environment wanted confirmation that if the customers did disconnect, they would have no ability to connect without Salt Box's knowledge and possibly contaminate the water system. Salt Box proposed that CHECAL may terminate service at any time upon giving at least two-years notice.

Regarding the increase in the notice period for termination of service to two-years from seven days, CHECAL stated: "I do not know of any agreement (apart from a lease on a vehicle), and especially with a utility, where the customer cannot cancel the service with at least a 30 days notice. This clause appears to create a utility monopoly within the area for Salt Box. There are many other suppliers in the area that can service CHECAL with a call and a connection fee (see Emerald Bay or North Springbank Water)."

The AUC noted that if CHECAL was to terminate service with Salt Box based on a short notice period, this may have unintended consequences for the ongoing viability of Salt Box. With a small customer base, termination of service would likely result in a negative impact on Salt Box's remaining customers. This potential effect of a termination of service by CHECAL supports a longer notice period. There should be sufficient time for Salt Box, as a monopoly water service provider to make arrangements for its remaining customers. In the event of termination of service, Salt Box may also have to make operational changes, which would likely take longer than 30 days.

The AUC found the two-year notice period proposed by Salt Box to be excessive. Such a length of time does not result in an appropriate balance of costs and risks considering the interests of the exiting customer, remaining customers, and Salt Box. Given the ongoing obligations of Salt Box to serve CHECAL during the notice period and Salt Box's overall small customer base, the AUC found that a notice period of 180 days effectively balances the interests of both Salt Box and customers.

In its comments, Salt Box also identified its concerns with the need to include a clause regarding disconnection fees. The AUC acknowledged that there should be a reconnection fee after a disconnection of service occurs.

The AUC found the reconnection fee of $2,500 to be reasonable, as it provides consistency between the two cooperatives served by Salt Box, CHECAL and Windmill. In addition, there should be a section in the T&Cs that sets out a reconnection fee because, without such a provision, there would be no certainty to Salt Box or CHECAL on the terms governing reconnection of service.

Regarding payment deadlines for CHECAL invoices, Salt Box stated: "invoices are paid [within] 10 days on our current agreements not 30 days." The T&Cs circulated by the AUC contained a 30-day period, which was consistent with the payment of invoices by Windmill to Salt Box.

The AUC noted under the current practice, CHECAL pays its invoices within 10 days, and that time period does not appear to be contentious. On this basis, the AUC amended Section 2 – Invoices, to a 10-day payment deadline for invoices to reflect the current practice.

The balance of the T&C's were not contentious and the AUC approved the T&Cs as amended.

CANADA ENERGY REGULATOR

Trans Mountain Expansion Project, Redwoods Golf Course Ltd. Detailed Route Hearing MH-021-2020, CER Letter Decision

Pipelines - Route Hearings

Background

On December 16, 2013, Trans Mountain Pipeline ULC ("Trans Mountain") filed an application with the National Energy Board ("NEB") under section 52 of the *National Energy Board Act* ("*NEB Act*") for a certificate of public convenience and necessity ("Certificate") authorizing the construction and operation of the Trans Mountain Expansion Project ("TMEP").

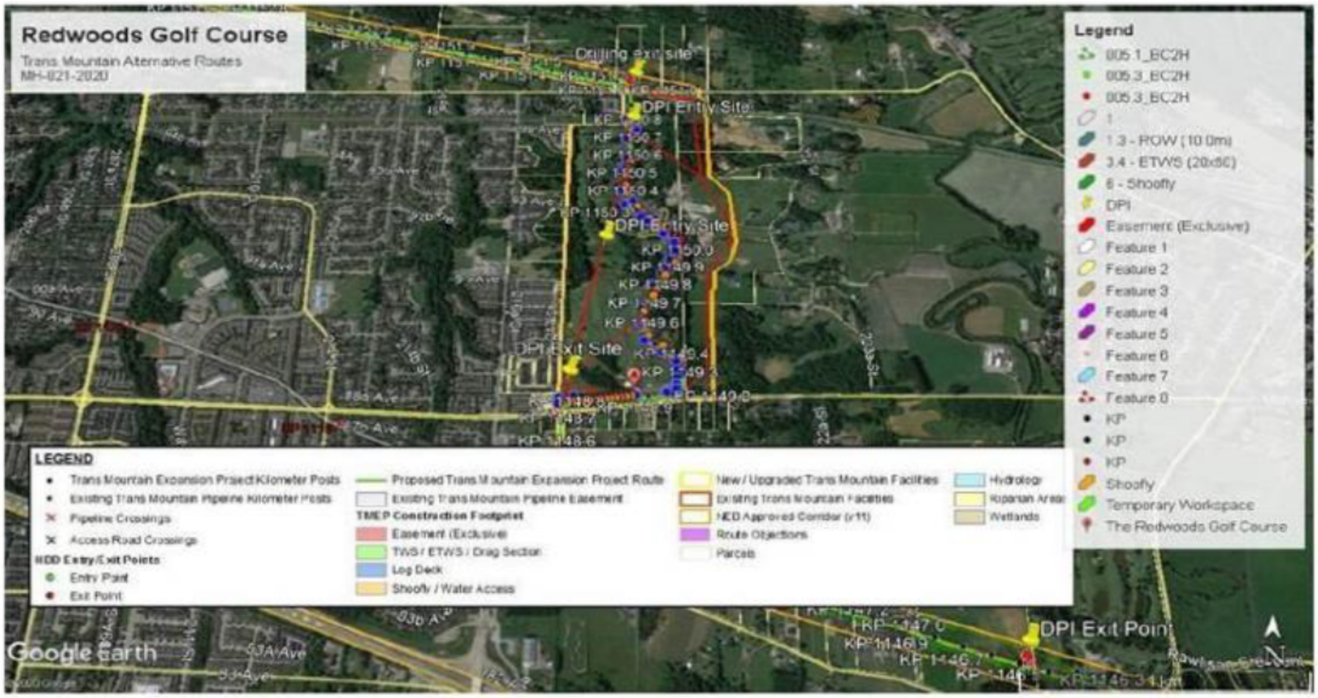
The TMEP includes twinning the existing 1,147-kilometre-long Trans Mountain Pipeline (TMPL) system in Alberta and British Columbia with approximately 981 kilometres of new buried pipeline; new and modified facilities, such as pump stations and additional tanker loading facilities at the Westridge Marine Terminal in Burnaby; and reactivating 193 kilometres of the existing pipeline between Edmonton and Burnaby. Trans Mountain requested approval of a 150-metre-wide corridor for the TMEP pipeline's general route.

Following an approval by Order in Council ("OIC"), an appeal, a second public hearing process, an NEB Reconsideration Report, and a further approval of the TMEP by OIC, the NEB issued Certificate OC-065. In July 2019, following a public comment process, the NEB set out how it would resume the TMEP detailed route approval process. The NEB directed Trans Mountain to file its Plan Profile and Book of Reference (PPBoR) for the entire TMEP route. Trans Mountain served landowners along the length of the TMEP with a notice that the detailed route approval process was underway, and placed notices in local publications. The notices indicated that landowners and Indigenous peoples with a continued or new objection to the proposed detailed route, or to the methods or timing of construction, were required to file a statement of opposition ("SOO"). On August 28, 2019, the *Canadian Energy Regulator Act ("CER* Act") came into force, repealing the *NEB Act*. As a result, the CER is considering approval of the PPBoR under the provisions of the *CER Act*.

Detailed Route Hearing MH-021-2020

Redwoods Golf Course Ltd. ("Redwoods") is the registered owner of lands noted as Tract PC 7494 in Segment 6.8 on PPBoR Sheet M002-PM03021-007 (C00974-9). Tract PC 7494 was referred to in this Decision as the "Lands". Figure 2 below shows Redwoods' suggested alternate route crossing the Lands (the "Western Route"), as indicated by the "pinned" red line, with the Trans Mountain proposed route in dark blue.

Figure 2 – Redwoods' suggested alternate route across the Lands (C07491, PDF page 18)



Is Trans Mountain's proposed detailed route the best possible detailed route?

The CER outlined Trans Mountain's routing criteria and guidelines, and acknowledged that they were reasonable and appropriate. The hierarchy of routing options were as follows:

(a) where practicable, co-locate the TMEP on or adjacent to the existing TMPL easement;

(b) where co-location with the TMPL is not practicable, minimize the creation of new linear corridors by installing the TMEP segments adjacent to existing easements or RoWs of other linear facilities, including other pipelines, power lines, highways, roads, railways, fibre-optic cables, and other utilities;

(c) if co-location with an existing linear facility is not feasible, install the TMEP segments in a new easement selected to balance safety, engineering, construction, environmental, cultural, and socio-economic factors; and

(d) in the event a new easement is necessary, minimize the length of the new easement before returning to the TMPL easement or other RoWs.

The CER stated that the above criteria and other guidelines prioritize safety and consider a number of competing factors, including physical constraints, while attempting to minimize environmental and socio-economic impacts on land and landowners. They are also flexible enough to incorporate reasonable mitigation measures to respond to concerns raised by landowners. Accordingly, the CER assessed whether Trans Mountain's proposed route reflected an appropriate application of its routing criteria, while considering its proposed mitigation measures to address Redwoods' concerns, and concludes that Trans Mountain applied its routing criteria appropriately.

The CER noted that the entire route on the Lands is new RoW, not paralleling the existing TMPL or another existing linear easement or RoW. Redwoods did not make submissions about the appropriate application of Trans Mountain's routing criteria. The CER accepted Trans Mountain's evidence that urbanization in Langley has encroached on the existing TMPL RoW and, as a result, agreed that it was appropriate for the TMEP pipeline to deviate from the TMPL in the area.

Neither party provided evidence of existing easements or RoWs of other linear facilities adjacent to which the TMEP pipeline could be situated. In the absence of such evidence, the Commission accepted that no such easements or RoWs present an appropriate opportunity for the TMEP pipeline to follow in this area.

Accordingly, the Commission was of the view that Trans Mountain properly applied its routing criteria, such that the third criterion applies. As per the routing criteria, the new easement for the TMEP pipeline should balance safety, engineering, construction, environmental, cultural, and socio-economic factors, and its length should be minimized before returning to the TMPL easement or other linear easements. Trans Mountain submitted that it considered and balanced these factors in selecting the proposed route. Redwoods identified some outstanding concerns with the proposed route and suggested the Western Route which, in its view, would address these concerns.

<u>Considering the Concerns Raised by Redwoods, Is Trans Mountain's Proposed Route the Best Possible Route?</u>

The Commission found that Trans Mountain's proposed route is, on balance, the best possible route, because:

- it reflects an appropriate application of Trans Mountain's routing criteria;
- Trans Mountain has appropriate plans in place to avoid or mitigate impacts of the proposed route, including the specific concerns raised by Redwoods;
- it appropriately reflects consideration of the golf course operations, including through its meandering route that avoids existing infrastructure, minimizes impacts to fairways and greens, and minimizes tree removal; and
- it is consistent with Trans Mountain's prior commitment to the Township of Langley to locate the pipeline on the eastern part of the Lands.

The CER was of the view that all but one of the concerns Redwoods raised about Trans Mountain's proposed route through the Lands are more accurately described as concerns with the proposed open-cut method of construction. The Commission was not persuaded by Redwoods' remaining concern that the length of the proposed route is longer than strictly necessary to cross the Lands, since length is one of many factors to consider in assessing the proposed route. Since Redwoods suggested the Western Route on the premise that it would be constructed using trenchless methods of construction, the solutions it offers are primarily associated with Redwoods' concerns about open-cut construction, rather than with the specific location of Trans Mountain's proposed route. Considering Redwoods' concerns about the proposed route, separately from its concerns about the proposed methods of construction, and Trans Mountain's responses to these concerns, the Commission found that Trans Mountain's proposed route is, on balance, the best possible route.

<u>Are Trans Mountain's Proposed Methods of Construction the Most Appropriate?</u>

The CER noted that Trans Mountain plans to install the TMEP using trenchless techniques for the crossing of 88th Avenue and 96th Avenue, and for identified fish-bearing watercourses within the Lands. Trans Mountain proposes conventional open-cut construction with a moderately or heavily restricted footprint on the remaining portion of the Lands.

In the CER's view, Trans Mountain's criteria to determine its proposed methods of construction on particular lands are reasonable and appropriate. They minimize the risk of construction failure, prioritize safety, and consider physical constraints both on the surface of the land and subsurface. In addition, temporary workspaces are located as much as possible on open and undeveloped lands to avoid proximity to residences, treed areas, and areas of environmental or cultural sensitivity. Where a landowner raises concerns, the Commission was of the view that the criteria are flexible enough to allow Trans Mountain to incorporate mitigation strategies in response. The Commission assessed Trans Mountain's proposed methods of construction on the Lands against these criteria, while also considering Redwoods' proposed trenchless method of construction, and concluded that Trans Mountain's proposed methods are, on a balance of probabilities, the most appropriate.

Is Trans Mountain's Proposed Timing of Construction the Most Appropriate?

Construction timing is scheduled between Q4 2021 and Q1 2022. The CER found that Trans Mountain's proposed timing of constructing the TMEP across the Lands is appropriate because construction in the winter will reduce the impact on golf course operations and allow the commencement of processes to restore the irrigation systems and soil, seeding, and sod replacement. The CER found that Trans Mountain's proposed timing of construction is the most appropriate.

Conclusion

Having decided that Trans Mountain's proposed detailed route is the best possible detailed route on the Lands, and that its proposed methods and timing of construction are the most appropriate, the Commission noted that it may issue an order approving the PPBoR for the Lands.