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

### *TransAlta Corporation v Alberta (Utilities Commission),* 2021 ABCA 232

***Leave to Appeal***

In this decision, the Alberta Court of Appeal ("ABCA") granted the application filed by TransAlta Corporation ("TransAlta") seeking leave to appeal the decision from the AUC dismissing the request from TransAlta for a preliminary ruling that certain issues were *res judicata* as having been determined in an arbitration between TransAlta and the Balancing Pool.

The ABCA determined that TransAlta satisfied the test for permission to appeal and granted permission to appeal the AUC decision on the following grounds that the AUC erred in law by failing to conclude that the arbitration result renders the Mine Issue (defined below) *res judicata* or subject to abuse of process, by:

(a) failing to identify and apply the correct legal test;

(b) concluding that the "context" of the Decommissioning Application (defined below) affects the legal meaning and application of the *Electric Utilities Act* definition of "generating unit"; and

(c) failing to provide transparent and intelligible reasons that cogently and logically support the outcome of the Ruling.

<u>Background</u>

Under s. 5 of the *Power Purchase Arrangements Regulation* ("*PPAR*"), an owner of a generating unit may apply to the AUC for payment from the Balancing Pool of its remaining uncollected costs to decommission the generating unit. TransAlta applied for the decommissioning costs of two generating units (the "Sun A units") at the TransAlta Sundance Power Plant (the "Decommissioning Application").

TransAlta argued that the mine is an associated facility within the definition of "generating unit" in the *Electric Utilities Act* ("*EUA*") and, therefore, a proportionate share of the costs of decommissioning the mine form part of the costs of decommissioning the Sun A units (the "Mine Issue"). TransAlta was engaged in another dispute with the Balancing Pool regarding the Balancing Pool's obligation to pay TransAlta the net book value of other generating units (Sundance B and C) at the Sundance Power Plant upon the termination of the power purchase arrangements for these units. The arbitration panel in that dispute concluded on August 23, 2019, that the mine was an "associated facility" of the Sundance B and C generating units within the meaning of a "generating unit". The Balancing Pool did not appeal or request to have this award set aside.

<u>AUC's Ruling</u>

Shortly before the arbitration noted above was scheduled to begin, the Balancing Pool brought a preliminary application in the Decommissioning Application before the AUC. It requested a ruling, as a question of law, whether the mine decommissioning costs were costs to be paid under s. 5 of the *PPAR.* The AUC denied the request. The Balancing Pool then applied for review and variance of the AUC denial of the request. The AUC denied the application for review and variance.

Following the applications by the Balancing Pool, TransAlta applied for an order declaring that the "Mine Issue" is *res judicata* for the purposes of its Decommissioning Application. TransAlta requested that this order be issued to prohibit the Balancing Pool and the Office of the Utilities Consumer Advocate ("UCA") from attempting to relitigate the issue in the current proceeding.

AUC's Decision

The AUC dismissed TransAlta's request for an order confirming that TransAlta is entitled to a proportionate share of the Highvalve Mine decommissioning costs as part of the Sundance A decommissioning costs to be determined through this proceeding.

The AUC noted that the context of the arbitration is different from the circumstances in which the issues arise in the AUC proceeding. The AUC determines decommissioning costs under a different enactment. The AUC noted it would make its own decision regarding the inclusion of mine costs in the calculation of decommissioning costs.

Test for Permission to Appeal

*Significance of Practice*

TransAlta submitted that the issue of how the doctrines of issue estoppel, *res judicata*, and abuse of process apply to administrative proceedings is an important question. It submitted that this appeal raises the two mischiefs that these doctrines are intended to protect against wasted time if the AUC reaches the same decision as to the arbitration panel and inconsistent decisions if the AUC comes to a different decision.

Regarding the importance of the practice in relation to the Power Purchase Arrangement regime, the AUC noted that the *PPAR* had expired and that it did not foresee any future circumstances where it will be making determinations relative to power purchase arrangements.

The ABCA saw merit in the argument regarding the doctrines of issue estoppel, *res judicata*, and abuse of process as it had not decided this particular issue, although it has confirmed that parties to an arbitration are bound by a prior arbitration award involving the same parties.

*Significance to the Proceedings*

The AUC submitted that the proposed grounds of appeal are not significant to the proceeding because TransAlta will not be forced to relitigate the Mine Issue. TransAlta argued that the appeal is significant as approximately one-third of its overall decommissioning costs claim turns on the Mine Issue.

The ABCA found the AUC position to be unclear. The AUC confirmed that it would hold the Balancing Pool and the UCA to their undertakings. At the same time, it stated that TransAlta would be compelled to proffer evidence and argument to support all decommissioning costs claimed in its application.

The ABCA found that TransAlta would be entitled to adduce evidence and fully argue the issue. The duplication of the considerable evidence and comprehensive argument in the arbitration persuaded the ABCA that this factor also favours granting permission to appeal.

Merits of the Appeal and Standard of Review

The ABCA found arguable merit in the proposed grounds for appeal.

Interlocutory Ruling

In disagreement with the AUC, TransAlta submitted that its request to the ABCA is not an interlocutory ruling but a final ruling that disposes of the *res judicata* issue and substantively affected the parties' rights. The ABCA determined that it did not need to determine if it is a final order. As the application included exceptional circumstances as the ones contemplated in *Workum* v *Alberta Securities Commission*, 2006 ABCA 181, it could hear the appeal before the administrative proceeding was completed.

ABCA Conclusion

The ABCA determined that TransAlta satisfied the test for permission to appeal. Permission to appeal the AUC's decision was granted.

## ALBERTA ENERGY REGULATOR

### *Invitation for Feedback on Revisions to Directive 040,* AER Bulletin 2021-21

*Oil and Gas - Update*

On June 2, 2021, the AER issued Bulletin 2021-21 seeking feedback on a new edition of *Directive 040: Pressure and Deliverability Testing Oil and Gas Wells*. The proposed new edition includes changes to modernize *Directive 040* by removing unnecessary oil and gas well test requirements and updating well test guidance to align it with today's well testing practices. The key changes the AER sought feedback on were the following:

- Modernized and updated guidance for minifrac tests, also known as diagnostic fracture injection tests, pressure gauge information, and drill stem tests.
- Increased the exemption eligibility criteria for the initial pressure test requirements on oil, gas, and step-out wells.
- Rescission of the requirement to conduct an absolute open flow deliverability test on new gas wells.
- Rescission of the requirement to conduct annual pressure tests for oil and gas pools under primary production.

The deadline for submitting feedback was set as July 4, 2021.

### *Invitation for Feedback on Proposed New Licensee Life-Cycle Management Directive,* AER Bulletin 2021-22

*New Directive*

The AER requested feedback on a proposed new directive regarding licensee life-cycle management. The directive supports the Government of Alberta's new *Liability Management Framework*. The AER noted that the proposed directive and comment form are available on the AER website. Feedback will be accepted through Sunday, July 25.

<u>Directive XXX: Licensee Life-Cycle Management</u>

Every energy resource development project has a life-cycle consisting of four stages: initiate, construct, operate, and close; liabilities need to be managed throughout. The AER announced that this directive:

- introduces a holistic assessment of a licensee's capabilities and performance across the energy development life-cycle, which will be supported by the licensee capability assessment ("LCA") system;
- introduces the Licensee Management Program, which outlines how licensee management will occur across the energy development life-cycle;
- introduces the Inventory Reduction Program, which sets mandatory closure spend targets for closure activities and spends by licensees;
- updates application requirements related to the licence transfer process; and
- describes security collection under the directive.

<u>Directive 006 Changes</u>

Changes would be made to *Directive 006* in phases while the AER transitions to the programs outlined in the new directive. In this first phase, requirements around licence transfer applications will be moved from *Directive 006* to the new directive once finalized. Subsequent phases will include additional changes to *Directive 006* and other AER directives related to liability management to align with the new *Liability Management Framework.*

***Mandatory Closure Spend Targets,* AER Bulletin 2021-23**
***Oil and Gas***

In accordance with the requirements of the Government of Alberta's new *Liability Management Framework* and its authority under section 3.014 of the *Oil and Gas Conservation Rules* ("*OGCR*"), as part of the Inventory Reduction Program, the AER set industry-wide closure spend targets. Closure spend targets will help increase the amount of closure work that is occurring in the province as licensees will be required to spend a minimum amount on closure annually.

Annually by July 31, the AER will release targets for a five-year period on the AER website. The first two years will be set, and the final three years forecasted.

| Year | Industry-Wide Mandatory Target |
|---|---|
| 2022 (Set) | $422 million |
| 2023 (Set) | $443 million |
| 2024 (Forecasted) | $465 million |
| 2025 (Forecasted) | $489 million |
| 2026 (Forecasted) | $513 million |

Starting January 1, 2022, each oil and gas licensee with liability associated with inactive infrastructure will be required to meet an individual annual mandatory closure spend target determined by the AER. Targets are based on the above liability and historical closure spending and take into consideration financial information as required through the AER's updated *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals.*

Licensees may still commit to a voluntary closure spend target that is more than their mandatory target to qualify for incentives. Further information about the inventory reduction program, closure targets, and associated incentives for an increased spend will be available in the fall.

To assist industry in preparing, the AER included examples of closure work and whether it will count towards the licensee's target.

***Invitation for Feedback on Directives 055 and 058,* AER Bulletin 2021-24**
***Oil and Gas***

The AER requested feedback on new editions of *Directive 055: Storage Requirements for the Upstream Petroleum Industry* and *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*. These directives were updated to incorporate the storage of large volumes of water such as produced water, water-based flowback, and oilfield landfill leachate in storage devices for reuse in hydraulic fracturing. The directives were revised to provide greater clarity and to remove redundant and outdated requirements.

*Directive 055* now includes technical requirements for engineered containment ponds and bladders with structural frames and expanded requirements for aboveground synthetically lined walled storage systems.

*Directive 058* now includes storage of water for reuse in hydraulic fracturing as a waste storage activity.

Several ancillary documents were also consolidated in the directives, including addendums, interim directives, informational letters, reports, and bulletins.

A comment form is available on the *Directive 055* and *Directive 058* webpages. Feedback will be accepted through Sunday, July 25, 2021.

***New Functionality Moving to OneStop,* AER Bulletin 2021-25**
***Oil and Gas - Submission Format and Requirements***

On July 8, 2021, the AER released new functionality to the OneStop platform.

Well Licence Resumptions and Wells System-Generated Cancellations

Well licensees will be able to submit an application to OneStop to resume activity on an existing well. Wells system-generated cancellations for expiries will now be auto-completed in OneStop.

Public Lands

The changes will allow an applicant to link *Environmental Protection and Enhancement Act* ("*EPEA"*) approvals to Public Lands in-situ applications based on specific disposition types, purposes, and activity codes. OneStop will exclude any identified *Master Schedule of Standards and Conditions* ("*MSSC*") approval clauses from Public Lands approvals that are identified as redundant with existing *EPEA* approvals. This update to the *MSSC* will be applied to all Public Lands applications submitted after the update.

Well Logs

Well licensees will be required to submit Log ASCII Standard ("LAS") and raster well logs through OneStop. Well log summary reports will no longer be required. *Directive 080: Well Logging* and an associated FAQ document will be updated to reflect these changes to submission requirements and will come into effect on July 8, 2021. These documents will not refer to OneStop directly. Instead, the more generic term "designated information submission system" will be used.

Record of Site Condition

Licensees will be required to submit all records of site conditions ("RoSCs") and associated professional reports through OneStop unless the submission is required under an *EPEA* approval for mining operations.

The Bulletin notes that the AER will hold training sessions on RoSC before and after the release and training sessions on well log submissions after the release.

***Benga Mining Limited Grassy Mountain Coal Project,* 2021 ABAER 010**
***Coal - Facilities***

In this decision, the AER and Canadian Environmental Assessment Agency ("CEAA") joint review panel ("JRP") found that the Benga Mining Limited ("Benga") Grassy Mountain Coal Project (the "Project") is not in the public interest. It was determined that the adverse environmental effects outweigh the positive economic impacts of the project. Benga's application was denied.

Introduction

Benga applied to the AER for approval to construct, operate and reclaim a new open-pit metallurgical coal mine in the Crowsnest Pass area. The proposed Project footprint covered 1521 hectares. The production capacity of the Project would be a maximum of 4.5 million tonnes of metallurgical coal per year over a mine life of approximately 23 years.

The Project would include surface mine pits and waste rock disposal areas, a coal-handling and processing plant with associated infrastructure, water management structures, an overland conveyor system, a rail loadout facility, and other facilities.

Benga Submissions

Benga submitted an environmental impact assessment ("EIA") for the Project to the AER and CEAA on November 10, 2015, and submitted an updated EIA on August 15, 2016. Based on its EIA, Benga submitted that the Project was not likely to result in significant adverse effects following the implementation of mitigation measures.

JRP Findings

The JRP found that in some cases, the claimed effectiveness of the proposed measures was overly optimistic and not supported by the evidence. The JRP found that Benga did not always apply a conservative approach to the identification and assessment of project effects.

The JRP found that Benga's reliance on future adaptive management meant that, in some cases, it did not provide important details regarding proposed mitigation measures. It further found that Benga's proposed adaptive management approach and plans were not sufficiently developed or detailed to allow for a confident conclusion that anticipated or unanticipated project effects would be effectively mitigated through adaptive management.

The JRP found that the Project would result in low to moderate positive economic impacts on the regional economy, but that Benga did not consider some risks that could reduce the magnitude of these positive impacts.

*Environmental Effects*

The Project is located in a sensitive mountain environment and has the potential to adversely affect the water quality of Gold Creek and Blairmore Creek, which are within the headwaters of the Crowsnest River, Oldman River, and South Saskatchewan River. These creeks contain populations of threatened westslope cutthroat trout. The Project would release contaminants, particularly selenium, into receiving surface waters.

Benga estimated that the mitigation measures it would implement would capture 95 or 98 percent of the selenium-rich contact water coming from the waste rock dumps, which modeling showed was necessary to achieve target selenium concentrations in the effluent and receiving streams. The JRP determined that the Project as proposed would not likely capture contaminants this efficiently. The JRP determined that Benga did not adequately describe or assess alternative, additional selenium mitigation measures it would pursue if its planned saturated backfill zones were not as effective as needed.

Benga predicted slight but chronic exceedances for a number of non-selenium contaminants, despite not taking a conservative approach to modeling water quality or capturing all potential sources of metal leaching in its model. A sulphate-adjusted, site-specific water quality objective for selenium in receiving waters downstream of the Project was suggested. The JRP did not find that this objective would protect surface water quality. Further, the JRP noted that no evidence was presented to demonstrate that any jurisdiction in the world has approved a sulphate-adjusted guideline for selenium.

The JRP found it likely that the costs of the long-term monitoring and treatment necessary to protect future water quality at and downstream of the site were underestimated. Benga appeared to rely heavily on its participation in the province's Mine Financial Security Program to respond to concerns about long-term treatment. This raised the concern that liability for long-term water quality management could be assumed by the taxpayers of Alberta.

The JRP concluded that the Project is likely to cause significant adverse environmental effects on westslope cutthroat trout and their aquatic habitat. Westslope cutthroat trout are listed as threatened under both the provincial *Wildlife Act* and the federal *Species at Risk Act* ("*SARA*"). The JRP determined that Benga did not adequately assess the potential impacts of the Project on fish and aquatic habitat.

Calcite was further identified as an issue and a danger to the habitat, given that there are no treatments to remove calcite from the creek once it precipitates onto substrates in a creek. Benga's assessment of the impacts of the Project on fish and aquatic habitat identified risks to species listed as threatened under the *SARA.* The JRP found that little information had been provided on these matters and that the proposed mitigation, including an offsetting plan, was likely not feasible or effective.

Regarding surface water quantity and flow, the JRP found that the Project would likely have a low to moderate adverse impact on the quantity of surface water flows in Gold and Blairmore Creeks. Because of uncertainties with water quality management, the presence of a threatened aquatic species, and the lack of a comprehensive flow augmentation plan, the JRP could not confidently conclude the extent or acceptability of the effects.

It was further concluded that the Project would not likely cause significant adverse effects on ground water quantity, flow, and quality or air quality. Any adverse impacts on air quality would be localized and limited to the area immediately surrounding the mine permit boundary. It was noted that Benga did likely underestimate the potential for, and effects of, worst-case wind-driven dust emissions.

*Human Health*

Benga's assessment of risk from exposure to dust in general and coal dust was limited in scope and, as a result, left uncertainty about the potential for increased health risks associated with dust. Confidence in the results of the human health risk assessment for the Project was low due to the lack of conservatism in the water quality modeling, changing risk estimates during the review process, and other limitations of the health risk assessment. Despite the uncertainties in the assessment, the JRP concluded that adverse project-related effects on human health are unlikely due to the conservative exposure assumptions used in the assessment.

*Conservation, Reclamation, and Closure*

Reclamation is the primary mitigation measure for many Project effects. The Project would be located in steep terrain within the highly diverse and specialized landscape of the Montane and Subalpine Natural Subregions of the Rocky Mountain Natural Region of Alberta.

While Benga submitted a proposed conservation and reclamation plan, the JRP concluded that this plan did not provide enough detail to allow for the assumption that reclamation would effectively mitigate Project effects on terrestrial resources or that the reclamation can be achieved. Particularly, the JRP was concerned by the uncertainty regarding the time it may take for the Project site to reach a stable and self-sustaining state that satisfies the requirements for reclamation certification.

The JRP was not satisfied that the proposed reclamation measures are technically feasible. It was further not satisfied that the measures would result in the restoration of various important vegetation species and communities affected or removed during the Project. The conservation and reclamation plan was also found to lack mitigation of the loss of rare plants and plant communities. The JRP also noted that uncertainties of the reclamation plan are compounded by the effects of climate change on long-term reclamation success.

*Social and Economic Effects*

The Project would have a moderately positive economic impact on the Crowsnest Pass area and a low impact on the remainder of Alberta and Canada. To estimate royalty revenues, Benga used a US$140/tonne long-term average price. It estimated that it would employ approximately 400 workers directly and pay approximately $990 000 and $490 000 annually in municipal taxes to the Municipal District of Ranchland No. 66 and the Municipality of Crowsnest Pass, respectively, over the life of the Project.

The JRP could not verify the magnitude of the estimated benefits as Benga did not submit methods and models to support its estimates. Additionally, the JRP was not confident that Benga's estimate of future royalty payments of $30 million per year was accurate. Benga did not submit a detailed financial feasibility model or provide a clear explanation to support its estimates. Nor did it provide an adequate explanation of why its royalty payments would be significantly higher than those of other bituminous coal mines in the province. The JRP found that Benga's estimated royalty payments were likely overstated. Similarly, the JRP did not have confidence in the tax estimates that Benga produced, as they came from the same model.

The JRP concluded that the Project has the potential to impose negative impacts on other economic sectors. At the same time, Benga's assessments did not include all factors that may reduce the positive economic impacts of the Project. These missing aspects included the potential for falling demand for or price of metallurgical coal later in the life of the Project. These declines could arise from a transition away from metallurgical coal as part of efforts to reduce greenhouse gas emissions.

Generally, the Review Panel found that Benga presented an overly optimistic economic analysis that did not adequately consider all economic risks.

*Effects on Indigenous Traditional use of Lands and Resources, Culture, and Rights*

The proposed Project is located within Treaty 7 territory, in the headwaters of the Oldman watershed. Indigenous groups emphasized the importance of the area and the watershed as a cultural landscape and source of traditional resources and the need to protect it.

The JRP specifically evaluated distinct but interrelated issues regarding the effects of the Project on Indigenous peoples. It assessed whether the Project would cause changes to the environment that would affect: current use of lands and resources for traditional purposes; physical and cultural heritage; any structure, site, or thing that is of historical, archaeological, paleontological, or architectural significance; or health and socio-economic conditions.

The JRP noted that all Treaty 7 First Nations and the Métis Region 3 signed agreements with Benga and provided letters stating they had no objection to the Project. Regardless, the JRP's assessment included an evaluation of the potential adverse effects the Project may have on Indigenous peoples. The JRP also considered the Project's effects on asserted or established Aboriginal or treaty rights and information regarding any measures proposed to avoid or mitigate the potential adverse effects of the Project on asserted or established Aboriginal or treaty rights.

The JRP determined that overall the Project would result in the loss of lands used for traditional activities. Further, the Project would have a significant adverse impact on physical and cultural heritage for the Kainai, Piikani, and Siksika Nations. The mitigation measures proposed by Benga were not sufficient to mitigate the potential adverse effects of the Project.

Based on the information provided by Benga and because each Indigenous group would experience the Project and its effects differently, the JRP could not complete an assessment of the effects of the Project on the socio-economic conditions of the individual Indigenous groups.

Decision of the JRP

The JRP noted that in its review, it considered its obligations and the guides provided by the *Canadian Environmental Assessment Act 2012,* the *Responsible Energy Development Act*, the *Coal Conservation Act*, the *Environmental Protection and Enhancement Act*, and the *Water Act*. These Acts, the *South Saskatchewan Regional Plan*, and submissions and views expressed by different parties were considered in evaluating whether the Project would be in the public interest.

The JRP concluded that the negative environmental effects on westslope cutthroat trout and surface water quality outweighed the Project's moderate positive economic impacts. As a result, the Project was not found to be in the public interest. The Review Panel repeated that the evaluations and submissions of Benga regarding the adverse environmental impacts, as well as the extent of the positive economic impacts, were optimistic. Yet, the adverse impacts on the environment were still estimated to be significant, and the positive economic impacts were only moderate in the area and low in the remainder of the country. The Project could, therefore, not be found to be in the public interest. The JRP denied the application.

## ALBERTA UTILITIES COMMISSION

***New AUC Rule 034 Approved and Rule 032 Amended,* AUC Bulletin 2021-12**

***Rates - Payment Deferral***

As of June 30, 2021 the AUC's approval of Rule 034: *Utility Payment Deferral Program Billing* and amendments to Rule 032: *Specified Penalties for Contravention of AUC Rules* including Appendix 1 – Table of Specified Penalties for Contraventions of AUC Rules is in effect. Rule 034 expires June 18, 2022.

On June 18, 2021, the repayment period for customers who deferred their utility bill payments under the *Utility Payment Deferral Program Act* ended. Any gas or electric bill payments that were not repaid will be recovered in separate gas and electric rate riders to be collected from all Alberta customers.

Rule 034 directs retailers to show these rate riders as separate line items on customer bills using the following nomenclature:

- Utility Deferral Adjustment–Electric or Utility Deferral Adjustment-E.
- Utility Deferral Adjustment–Natural Gas or Utility Deferral Adjustment-NG.

The alternative wording will be used by retailers who have billing systems that cannot accommodate the full name. The full name of the rider will be added in the message areas for customer bills for those retailers who use the alternative wording.

***AUC Evaluation of Performance-Based Regulation in Alberta,* AUC Decision 26356-D01-2021**

***PBR - Rates***

The AUC evaluated the performance of the first two terms of performance-based regulation ("PBR") of the electricity and gas distribution utilities operating in Alberta. The AUC, in this decision, determined that PBR met many of the objectives set out in the founding PBR principles. A third PBR term ("PBR3") commencing in 2024, following a one year cost-of-service ("COS") rebasing year in 2023, is supported.

<u>Background and Procedural Summary</u>

The PBR plans under which the electric and natural gas distribution rates are set are established in Decision 20414-D01-2016. The plans are effective until December 31, 2022, and apply to the electric distribution facility owners ("DFOs") ATCO Electric Ltd., FortisAlberta Inc. ENMAX Power Corporation, and EPCOR Distribution and Transmission Inc. They also apply to the natural gas DFOs ATCO Gas and Pipelines Ltd. and Apex Utilities Inc. These utilities will collectively be referred to as "the Utilities".

<u>PBR Performance to Date Evaluated Against the AUC's PBR Principles</u>

*Principle 1. A PBR Plan Should, to the Greatest Extent Possible, Create the Same Efficiency Incentives as Those Experienced in a Competitive Market While Maintaining Service Quality*

In evaluating the performance of PBR in Alberta according to Principle 1, the AUC separately evaluated if PBR created, to the greatest extent possible, the same efficiency incentives as those experienced in a competitive market; and if service quality was maintained.

Regarding the efficiency incentives, the AUC concluded that PBR created efficiency incentives, but not to the greatest extent possible. The Utilities stated that they could not quantify all the efficiencies and that some efficiencies were not tracked as this was excessively burdensome. Additionally, the Utilities indicated that it is not always possible to attribute efficiencies solely to PBR incentives. This was because some initiatives would have been implemented regardless of the regulatory regime.

The Utilities agreed that PBR encourages the introduction of cost-saving programs as they can retain earnings in excess of their approved return on equity ("ROE") arising from savings resulting from these programs.

Issues were brought by interveners regarding the need to quantify the cost savings resulting from any specific initiative or program implemented as a result of PBR. They argued that the Utilities' overall performance should be evaluated according to the fair return standard during the PBR terms.

Industrial Power Consumers' Association of Alberta ("IPCAA") proposed comparing achieved earnings to approved earnings. The AUC found that the method proposed by the IPCAA supports that the Utilities responded to PBR incentives in the same way as would have been expected in a competitive market. In this respect, the AUC noted that PBR was successful. However, the AUC agreed with the Utilities in finding that quantifying the efficiencies created as a result of PBR incentives may not be as simple as suggested by the method of the IPCAA.

Further, the AUC found that PBR may not have created the same efficiency incentives as those experienced in competitive markets to the greatest extent possible. The AUC accepted that, as suggested by evidence submitted by the City of Calgary, PBR may not have accurately reflected the economic realities in Alberta, particularly in consideration of the COVID-19 pandemic. Further, the AUC found that PBR did not achieve, to the greatest extent possible, the same efficiency incentives as a competitive market for Utilities that have distribution and transmission functions. It based this conclusion, in part, on the fact that general operations and maintenance ("O&M") allocations to transmission have increased significantly more than the allocations to distribution over the same time period while noting that the divergence could have been based on other factors such as the high number of transmission line constructions.

The AUC found that the Utilities have maintained service quality during the PBR terms. It based this finding on data submitted by the Utilities under Rule 002 reports. Rule 002 sets the minimum service quality standards and reporting requirements for the Utilities. Some Utilities reported, beyond meeting the requirements, that the requirements of Rule 002 had been exceeded, particularly in customer service and response time measures.

*Principle 2. A PBR Plan Must Provide the Company with a Reasonable Opportunity to Recover its Prudently Incurred Costs Including a Fair Rate of Return*

Provincial legislation governing the regulation of distribution utilities requires the AUC to provide the utility with a reasonable opportunity to recover its prudently incurred costs, including a fair rate of return. The AUC noted that, as stated by the ABCA in *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2014 ABCA 397, PBR does not guarantee a return. It only guarantees the opportunity to earn a return.

The AUC was satisfied that this principle was achieved. Over the eight-year period and seven utilities evaluated, there were only eight instances in which the actual ROE was below the approved ROE. In the remaining 48 instances, the actual ROE exceeded the approved ROE, often by significant amounts.

*Principle 3. A PBR Plan Should be Easy to Understand, Implement and Administer and Should Reduce the Regulatory Burden Over Time*

Parties submitted that there were some successes in improving regulatory efficiency and reducing regulatory burden through the implementation of the PBR plans. These were largely attributable to the implementation of routine annual PBR rate adjustment filings and the adoption of the K-bar mechanism instead of capital trackers in the 2018-2022 PBR plan. Additional regulatory efficiencies identified included reductions to overall processing time, scoping issues and setting submission length limits in AUC proceedings. The AUC did note that some efficiency initiatives were implemented to improve adjudicative efficiency and were not specific to the PBR plan, even though they were implemented during the same period.

The parties took different positions regarding the achievement of Principle 3 during the two PBR terms. The annual PBR rate adjustment filings that are routine, regular, and mechanical in nature allowed for an expedited review by the AUC and customer groups while allowing the Utilities to plan for the development of their applications and any subsequent related proceedings. The introduction of a K-bar mechanism in lieu of the legacy capital tracker mechanism reduced the number of regulatory proceedings by avoiding the need to forecast and review the vast majority of capital spending, activities that required a lot of time and effort from all stakeholders. PBR still needs improvement to improve regulatory efficiency and to reduce the burden, and make it easier to understand. The AUC concluded that future PBR plans would benefit from clearer rules and parameters.

*Principle 4. A PBR Plan Should Recognize the Unique Circumstances of Each Regulated Company that are Relevant to a PBR Design*

The AUC recognized the unique circumstance of each utility in designing the first and second PBR terms. It developed PBR plan features to recognize a utility's circumstances, including a revenue-per-customer cap design for natural gas distribution utilities and a price cap for electric distribution utilities and rebasing the current 2018-2022 PBR plan using historical O&M and capital spending during the 2013-2017 PBR term specific to each utility.

Utilities submitted that the inflation factor, which impacts what rates are established, did not always accurately represent the economic circumstances in Alberta. A number of Utilities also submitted that the X factor value, representing the productivity offset, in the 2018-2022 PBR term is not reflective of current expected productivity growth in the utility sector. The Utilities were also concerned with obtaining sufficient capital funding to keep pace with the new trends affecting the grid.

While the AUC found that other PBR plan features contributed heavily to reaching Principle 4 during the PBR terms, it would evaluate modifying the I and X Factors and any incremental funding provisions.

*Principle 5. Customers and the Regulated Companies Should Share the Benefits of a PBR Plan.*

Disagreement arose among parties regarding the achievement of Principle 5. The Utilities Consumer Advocate ("UCA"), Consumers' Coalition of Alberta ("CCA") and IPCAA agreed that PBR has resulted in enhanced efficiencies and cost savings for the Utilities, but consumers have yet to benefit. This is proved by the Utilities' consistent earnings above the approved ROE. It was suggested that an earnings sharing mechanism ("ESM") should be incorporated in the next PBR plan to allow customers to share in the benefits of PBR. Utilities opposed the ESM, arguing that it counteracts PBR incentives and increases the regulatory burden.

The Utilities submitted that customers did benefit during the PBR terms as they experienced lower rates than what would have been in place under COS regulation. The AUC agreed with the Utilities and with calculations provided by the Utilities that suggested that under both PBR plans, customers experienced lower rates under PBR than would be expected under COS regulation.

The AUC concluded that Principle 5 was not adequately met over the two PBR terms. Although customers saw lower rates under PBR than would be expected under COS regulation, and some sharing of savings occurred during the rebasing for the 2018-2022 PBR plans, rates increased during the economic downturn while utility earnings at the same time were excessive.

As a result, and to ensure that 2023 COS rebasing achieves objectives of Principle 5, the AUC will permit the Utilities to develop its 2023 forecast on its own accord. Utilities are directed to quantify and demonstrate how the efficiencies found and cost reductions achieved during the current PBR term are reflected in their forecast revenue requirement and how it will be passed on to customers. As far as Utilities are not able to quantify the efficiencies, they are encouraged to propose their own mechanistic methods as part of the 2023 COS proceedings to ensure ratepayers receive the benefit of reduced utility costs achieved during the PBR term.

<u>Conclusions from the Evaluation of PBR in Alberta and Next PBR Term</u>

On balance, PBR has achieved many of the objectives that were set out in the founding PBR principles. However, the AUC found that there are areas for improvement. The AUC found it to be in the public interest that the distribution Utilities return to a third PBR term commencing in 2024, upon completion of the 2023 COS year.

Future PBR plans should be more reflective of ongoing economic conditions. To facilitate this, a review of incremental capital funding provisions and of the I factor; and a consideration of introducing a mechanism to share earnings was suggested and supported. The AUC is also looking to simplify future PBR plans in support of making it easier to understand, implement and administer.

***AUC Letter Dismissing the Consumers' Coalition of Alberta's Application for a Review and Variance of Decision 25938,* AUC Disposition 26527-D01-2021**
***Review and Variance - Rates***

In this letter, the AUC dismissed the application from the Consumers' Coalition of Alberta ("CCA") for a review and variance ("R&V") of Decision 25938-D01-2021. In Decision 25938-D01-2021 (the "Original Review Decision"), a Review Panel of the AUC approved ATCO Electric Ltd.'s ("AE")'s application to review the AUC's directions in Decision 24805-D02-20202 (the "Compliance Decision"), related to the issue of the calculation of AE's income tax expense.

As part of its findings in the Original Review Decision, the Review Panel found that for regulatory purposes, the accounting required a deduction for the debt portion of the allowance for funds used during construction ("AFUDC") in calculating regulatory income tax expense. Ultimately, the Review Panel granted AE's request and revised the directions from the compliance decision, and required AE to file a second stage variance application to adjust the debt portion of AFUDC in determining AE's regulatory income tax expense.

The CCA, in this review application, argued that the AUC had erred in fact, law or jurisdiction by allowing AE to maintain amounts in its transmission revenue requirement and directing customers to pay for these amounts that are not just and reasonable.

<u>Should the AUC Reconsider Issues Regarding the Calculation of the Income Tax Expense Determined in its Original Review Decision, Decision 25938-D01-2021, Due to an Error in Fact, Law or Jurisdiction?</u>

The CCA argued that the original Review Panel had erred by finding that a net equity deduction is not permissible for statutory income tax purposes and that the equity component of AFUDC is the portion of the financing expense funded by equity, for which there is no offsetting expense. The CCA alleged that:

1. The AUC made a reviewable error by erring in fact or law by determining without compelling fact-based evidence the statutory tax requirements applicable to AFUDC equity;
2. The AUC made a reviewable error by erring in law or jurisdiction by suggesting a statutory interpretation of the *Income Tax Act* that has no basis within the *Income Tax Act*; and
3. The AUC has erred in finding that there should be an increase in income taxes paid by ratepayers as a result of the inclusion of AFUDC in rates.

In considering the review application, the current Review Panel considered that principles of finality and certainty are engaged. Finality allows parties to AUC proceedings to rely on AUC decisions once they are issued and the period to challenge them through the administrative review or court process has expired. The review process is not an opportunity for parties to re-argue matters or express concerns that they chose not to raise at first instance.

The correct calculation of the AFUDC portion of income tax was at issue in the proceedings leading to Decision 22742-D01-2020, Decision 24805-D02-2020, and Decision 25938-D01-2021. The AUC found that the original Review Panel was aware of the issues of statutory income tax and the treatment of AFUDC under regulatory income tax. This is particularly evident in the findings noted in paragraphs 60-70 of the Original Review Decision. Accordingly, the panel reviewing the CCA's application found that the issues alleged by the CCA had been considered in the original review proceeding. The AUC was, in this proceeding, not persuaded that it should exercise its discretion to allow new evidence on the calculation of the AFUDC portion of the net utility earnings before tax calculation of the regulatory income tax expense for AE's 2018-2019 revenue requirement. Accordingly, there was no error requiring a review.

Conclusion

The current Review Panel found that the CCA did not demonstrate the existence of an error of fact, law or jurisdiction that could lead the AUC to materially vary or rescind the decision. It found that there had been a reasonable opportunity to provide calculations or submissions in the original review proceeding and to comment on the income tax borne by ratepayers. As a result, it was not necessary for the AUC to exercise its discretion and to adjudicate new evidence in this review application. The CCA's application for review was dismissed.

***Alberta Electric System Operator Approval of New Alberta Reliability Standard VAR-002-AB-4.1 and Retirement of Existing Alberta Reliability Standard VAR-002-AB-3,* AUC Decision 26544-D01-2021**

***Electricity – Market***

In this decision, pursuant to subsection 19(6) of the *Transmission Regulation,* and based on the recommendation of the Alberta Electric System Operator ("AESO"), the AUC approved the retirement of Alberta Reliability Standard VAR-002-AB-3, *Generator Operation for Maintaining Network Voltages*. As the replacement, the AUC approved the new Alberta Reliability Standard VAR 002-AB-4.1, *Generator Operation for Maintaining Network Voltage.*

Introduction and Background

Pursuant to subsection 19(4)(b) of the *Transmission Regulation*, the AESO submitted a recommendation to approve the retirement of the existing Alberta Reliability Standard VAR-002-AB-3 to the AUC.

Subsections 19(5) and 19(6) of the *Transmission Regulation* require that the AUC approve or refuse to approve each reliability standard in accordance with the recommendation of the AESO unless an interested person satisfies the AUC that the AESO's recommendation is technically deficient or not in the public interest. Following the notice of application issued by the AUC, no such claims were submitted.

The proposed VAR-002-AB-4.1 was developed based on North American Electric Reliability Corporation ("NERC") VAR-002-4.1, *Generator Operation for Maintaining Network Voltage Schedules*. VAR-002-AB-3 is based on the previous NERC version of the standard. The AESO proposed the adoption of the new standard to align with NERC standards.

To adopt the new proposed standard in the Alberta electricity market, the AESO identified necessary variances. These variances include a change in the threshold set in VAR-002-AB-3 from a maximum authorized real power rating of 4.5 megawatts ("MW") to 5 MW. Additionally, the requirements in VAR-002-AB-4.1 have been amended so that when the control mode of applicable devices is restored within 30 minutes, notification to the AESO is not required. The revision to R4 of NERC standard VAR-002-4.1, which does not require a report when a status or capability change occurs to the individual generating units of dispersed power-producing resources, was not adopted.

AUC Findings and Decision

The AESO is required to consult with the market participants it considers likely to be affected by the adoption of reliability standards, according to subsection 19(4) of the *Transmission Regulation.* The AESO is also required to forward the proposed reliability standard to the AUC for review, with a recommendation that the AUC approve or reject them. The AUC was satisfied that the AESO had met the requirements.

The AESO forwarded the proposed new VAR-002-AB-4.1 and the retirement of VAR-002-AB-3 to the AUC with a recommendation that the AUC approve them. No interested party filed an objection with the AUC indicating that these changes are technically deficient or not in the public interest. The AUC accordingly approved the changes recommended by the AESO.

***Alberta Electric System Operator Approval of Retirement for Alberta Reliability Standard VAR-002-WECC-AB-1,* AUC Decision 26542-D01-2021**

***Electricity - Markets***

In this decision, pursuant to subsection 19(6) of the *Transmission Regulation*, and based on the recommendation of the Alberta Electric System Operator ("AESO"), the AUC approved the retirement of VAR-002-WECC-AB-1, effective as of June 16, 2021.

Introduction

Pursuant to subsection 19(4)(b) of the *Transmission Regulation*, the AESO forwarded a recommendation to approve the retirement of existing Alberta Reliability Standard VAR-002-WECC-AB-1, *Automatic Voltage Regulators and Voltage Regulating Systems,* to the AUC.

Subsections 19(5) and 19(6) of the *Transmission Regulation* require that the AUC approve or refuse to approve each reliability standard in accordance with the recommendation of the AESO unless an interested person satisfies the AUC that the AESO's recommendation is technically deficient, or not in the public interest. Following the notice of application issued by the AUC, no such claims were submitted.

AUC Findings and Decision

The AESO is required to consult with the market participants it considers likely to be affected by the adoption or creation of reliability standards, according to subsection 19(4) of the *Transmission Regulation*. The AESO is also required to forward the proposed reliability standard to the AUC for review, with a recommendation that the AUC approve or reject them. The AUC found that the AESO had met these requirements.

The AESO forwarded the proposed retirement of VAR-002-WECC-AB-1 to the AUC with a recommendation to approve the retirement. No interested party filed an objection with the AUC indicating that the retirement of VAR-002-WECC-AB-1 is either technically deficient or not in the public interest.

The AUC accordingly approved the retirement based on the recommendation and pursuant to subsection 19(6) of the *Transmission Regulation.*

***Alberta Electric System Operator Review and Variance of Decision 26215-D01-2021,* AUC Decision 26215-D02-2021**

***Electricity - Rates***

In this decision, the AUC granted the application from the Alberta Electric System Operator ("AESO") for review and variance ("R&V") of Decision 26215-D01-2021. The AUC approved the AESO's request to change the effective date for Section 3 of the Independent System Operator's ("ISO")'s tariff.

Review and Variance

In Decision 26215-D01-2021 (the "Decision"), the AUC approved, in part, changes to the terms and conditions of the ISO tariff to come into effect on July 1, 2021.

On May 19, 2021, the AESO, on the post-disposition record of this proceeding, requested that the AUC defer the date for the new and amended language in Section 3 of the ISO tariff, which relates to the adjusted metering practice ("AMP"), to become effective.

The sections of the approved ISO tariff that related to the substation fraction methodology involved changes to subsection 4.5(5) of the ISO tariff, as well as the change to the AESO's consolidated authoritative document glossary ("Glossary"). The effective date of these sections would remain unchanged.

The AUC found it in the public interest to review and vary the effective date of subsections 3.2(2), 3.6(2) and 3.6(3), and new subsection 3.6(4) of the ISO tariff to a date to be specified by the AUC in its approval of the AMP implementation plan that has yet to be filed by the AESO. The AUC found the review and variance was in the public interest because:

(a) granting the AESO's request corrects what the AESO described as an "unworkable situation" in terms of compliance with Section 3 of the ISO tariff and certain sections of ISO rules"; and

(b) the AMP implementation plan is meant to comprehensively address all factors involved in implementing the AMP. Accordingly, granting the AESO's request provides parties with an opportunity to gain important clarity regarding how the AMP implementation plan will impact them before it is approved by the AUC and takes effect.

Accordingly, the affected paragraphs of the Decision were changed. The AUC clarified that it was not varying the language of section 3, but only the effective date of varied provisions.

***AltaLink Management Ltd. Application for Sale of Foothills Property*, AUC Decision 26551-D02-2021**
***Gas-Facilities***

In this decision, the AUC provided its reasons for approving the application from AltaLink Management Ltd. ("AML") to sell its Foothills Service Centre property (the "Foothills property"). In approving the transaction as being outside of the ordinary course of business of AML under section 101(2)(d) of the *Public Utilities Act* ("*PUA*"), the AUC determined that the sale would not result in harm to customers.

Issues

*Is AUC Approval Under Section 101(2)(d) of the Public Utilities Act Required?*

The AUC considered whether the proposed disposition of the Foothills property was inside the ordinary course of business under section 101(2)(d) of the *PUA*. In finding that the disposition was outsides the ordinary course of business, the AUC recognized that the value of the property ($4 million) is relatively small in comparison to AML's rate base.

At the time of the application, the Foothills property was in use for storage and other uses. AML had determined a plan that would allow AML to safely move people, equipment and materials to other locations. As a result, the Foothills property would be surplus for utility service and could be retired when it is sold.

However, the submitted information suggested to the AUC that AML had only engaged in few similar transactions in the past fifteen years. Accordingly, the transaction could not be characterized as being in the ordinary course of business. Further, while the value of the proposed transaction was relatively small in comparison to the rate base, the AUC found that the value is material for its analysis of whether the transaction is within the ordinary course of business. The proposed sale will provide for proceeds of $4 million and a net book value of $5.2 million. These values, particularly the net book value, represent a departure from the net book value of the sale of the St. Albert facilities, which had sales proceeds of $3.1 million, and the net book value of $2.0 million. The sales transaction of the St. Albert facilities was the only similar sales transaction that AML provided detail for.

In considering these factors, the AUC determined that the proposed sale was outside the ordinary course of business of AML. Accordingly, section 101(2)(d) of the *PUA* requires that the AUC approve or deny the disposition.

*Should the AUC Approve the Disposition*

In considering the approval under section 101(2)(d) of the *PUA*, the AUC applies a "no-harm test". After examining the sale in the context of potential financial effects and service level effects to customers, the AUC determined that the transaction would not result in any such harm. The AUC was further satisfied that utility rates will not be adversely affected. AML is required to remove the net book value of the Foothills property from its regulated rate base at its earliest opportunity following the completion of the sale and the disposition.

***AltaLink Management Ltd. 2019 Deferral Accounts Reconciliation Compliance Filing to Decision 25913-D01-2021 and Decision 26278-D01-2021,*** **AUC Decision 26500-D02-2021**
***Electricity - Rates***

On May 13, 2021, the AUC issued its decision regarding AltaLink Management Ltd. ("AML")'s 2019 projects deferral accounts reconciliation compliance application related to Decision 25913-D01-20212 and Decision 26278-D01-2021. In this decision, the AUC approved the addendum to Proceeding 26500 filed by AML seeking approval of a one-time billing to the Alberta Electric System Operator ("AESO") in the amount of $42.4 million to dispose of the final settlement balances approved in Decision 26278-D01-2021.

AML provided an updated and adjusted summary of deferral accounts that indicated adjustments totaling $42.4 million. These are composed of a charge of $8.1 million for January 1 to December 31, 2016; $33.2 million between January 1 and December 31, 2017; and $1.1 million between January 1 and December 31, 2018.

The AUC found that AML's request for approval to dispose of its final settlement balances for 2016-2018 of $42.4 million through a one-time billing to the AESO is consistent with the findings from Decision 26278-D01-2021 and Decision 26500-D01-2021 and was approved as filed.

***ATCO Electric Ltd. 2018-2019 General Tariff Application Second Compliance Filing,*** **AUC Decision 26264-D01-2020**
***Electricity - Rates***

In this decision regarding the compliance with directions in decisions 24805-D01-2020, 24805-D02-2020, 25139-D01-2020, and 25282-D01-2020 of ATCO Electric Ltd. ("AE"), the AUC:

- approved revenue requirements of $676,400,000 and $679,400,000, for 2018 and 2019, respectively;

- required AE: to file, as a post-disposition filing in Proceeding 26264, its revised minimum filing requirement schedules reflecting the AUC determinations on the recovery of costs provided to affiliates and services to outside parties through revenue offsets; and the Variable Pay Program ("VPP") expense; and

- directed AE to file a revised Rule 005: *Annual Reporting Requirements of Financial and Operational Results* report comparing actual results with its approved forecast for 2018 and 2019.

<u>Responses to Directions from Decision 24805-D02-2020: 2018-2019 GTA Compliance Filing Requiring Further Analysis</u>

Direction 2 – 2018 full-time equivalents ("FTE")s and Direction 3 – 2019 FTEs of Decision 24805-D02-2020 required AE to update its tariff application to reflect its actual 2018 and 2019 FTEs, and update its revenue requirement and all supporting schedules to reflect the actual labour and fringe costs.

In response to these directions, AE adjusted its operations and maintenance ("O&M") and capital labour and fringe costs in its minimum filing requirement ("MFR") schedules.

In response to a request from the AUC, AE stated that it had not updated the revenue offsets to match the adjusted labour costs charged to affiliates and services to outside parties as a result of updating for actuals, as this was not required by Direction 2. The AUC disagreed and determined that AE had been required to update its revenue offset schedule. The AUC expected AE to update its revenue offset schedule to account for the additional labour services and costs to be recovered from ATCO affiliates and outside parties rather than from transmission ratepayers.

In Response to Direction 4, AE provided an overhead burden rate calculation. The AUC found it unclear why an equal and offsetting adjustment to increase O&M expense for the overhead costs would be required for the additional services provided to affiliates and outside parties when costs included in AE's forecast costs, which form part of the overhead costs, have been updated to include costs that appear to be included in the overhead burden rate calculation.

The AUC determined that an overhead burden rate should be applied to the added labour costs of providing service to affiliates and outside parties. As AE did not provide calculations for its total labour and fringe costs that should have been recovered from affiliates and outside parties, the AUC estimated the overhead costs AE should have recovered from its affiliates and from services to outside parties. The AUC estimated that compliance with directions 2 and 3 requires AE to adjust its revenue offset to account for the adjustment to the noted costs and overhead charges. AE was directed to reduce its revenue requirement by $6.1 million in 2018 and $3.9 million in 2019 to properly reflect the allocation and recovery of labour and fringe amounts used to provide services to affiliates and outside parties in those years.

The AUC directed AE, in future GTAs, to identify the number of O&M and capital FTEs that provided, or are forecast to provide, services to facilities and affiliates and services to outside parties. The AUC directed this to solve issues of transparency.

In Decision 24805-D02-2020, the AUC required updated information on the VPP eligible labour dollar amounts to approve AE's VPP forecast amounts. In Direction 8, the AUC noted that responses to Direction 1 impact the allocation of VPP amounts in AE's MFR schedules. AE was directed to update its VPP amounts to reconcile these schedules with any changes made in response to other directions.

In response to an information request, AE demonstrated that its revised VPP amounts included in the application were 80 percent of the 2018 and 2019 actual eligible payout amounts.

The AUC determined that there was uncertainty regarding the use of the word "labour". The "labour dollar per FTE" amount used to calculate the revenue requirement adjustment for the changes to the 2018 and 2019 FTEs in Proceeding 24805 did not include variable pay. The AUC rejected AE's use of the "labour dollar per FTE" method. It noted that in directing the use of actual labour and fringe, the term "labour" refers to "wage" or "salary". AE was directed to use its actual labour and fringe amounts in directions 2 and 3.

In response to further requests from the AUC, AE calculated that VPP costs would increase by $0.5 million in 2018 and decrease by $0.8 million in 2019. The AUC determined that AE's VPP expenditures should be $ 4.3 million and $3.5 million in 2018 and 2019, respectively. Therefore, to properly reflect the allocation and recovery of VPP amounts, the revenue requirement must be increased by $0.2 million in 2018 and decreased by $0.3 million in 2019.

Direction 9 of Decision 24805-D01-2020 was issued in regards to the allowance for funds used during construction ("AFUDC") treatment for the purposes of calculating income tax expense. It required AE to remove the AFUDC amount from "utility earnings before tax" for the purposes of calculating its income tax expense. The AUC was satisfied that AE complied with this Direction.

Consolidated Filing Adjustments Required to Revenue Requirement

The AUC determined that more adjustments are needed to comply with directions 2, 3, and 8 of Decision 24805-D01-2020. However, in the interest of regulatory and administrative efficiency, AE was not directed to file a third compliance filing to make the adjustments required to comply with these three directions. The AUC required that to comply with directions 2 and 3, AE reduces its 2018 and 2019 revenue requirements by $6 million and $3.9 million, respectively and, to comply with Direction 8, further add $0.2 million to its 2018 revenue requirement and subtract a further $0.3 million from its 2019 revenue requirement.

***ATCO Electric Ltd. 2021 Performance-Based Regulation Rate Implementation, AUC Decision 26360-D01-2021***
***Electricity-Rates***

In this decision, the AUC considered the application from ATCO Electric Ltd. ("AE") and ATCO Pipelines Ltd. (together, the "ATCO Utilities") in response to the AUC's direction regarding their respective treatment of the deferred amounts resulting from the 2021 rate relief approved in Decision 26170-D01-2020.

The AUC approved a collection for the 2021 deferred amounts related to the ATCO Utilities' 2021 distribution rates beginning January 1, 2022, and the implementation of a 12-month shortfall rider (Rider S) to collect outstanding depreciation expense balances from 2018 to 2020 effective July 1, 2021, for ATCO Gas and Pipelines ("ATCO Gas") The AUC also approved carrying costs on the 2021 deferred amounts.

<u>Introduction and Background</u>

In Decision 26170-D01-2020, the AUC approved a rate freeze in respect of the ATCO Utilities' 2020 electricity and gas rates. This deferral of the 2021 distribution rates increase did not extend to flow-through charges, rate riders of the 2021 electric transmission access rates, and went into effect on January 1, 2021.

In response to directions issued by the AUC in Decision 26170-D01-2020, the ATCO Utilities filed the application subject to the current decision to address the collection of the 2021 deferred amount from their respective electricity and gas distribution customers.

<u>Issues</u>

*The Magnitude of 2021 Deferred Amounts*

The ATCO Utilities estimated the 2021 deferred amounts, prior to carrying costs, to be $62 million for AE and $53 million for ATCO Gas (net of Rider S) by the end of 2021. These amounts will be captured in a deferral account and recorded monthly.

The ATCO Utilities calculated the estimated 2021 deferred amounts by comparing the rates that have been in place for 2017 to the interim rates approved in Decision 26170-D01-2020 for both utilities. The deferred amounts were calculated using the forecast billing determinants as approved in their respective 2021 annual performance-based regulation ("PBR") rate adjustment decisions.

ATCO Gas indicated that its approved 2021 PBR rates included approval of the collection of depreciation expenses balances of approximately $74 million from 2018 to 2020 through Rider S in 2021 and 2022. The total impact of the 2021 rate deferral for ATCO Gas was estimated to be $91 million on December 31, 2021, before carrying costs.

The AUC was satisfied with the calculations used to determine the estimated 2021 deferred amounts. The AUC was also satisfied by the methodology proposed by the ATCO Utilities that will determine the actual 2021 deferred amounts on a monthly basis using actual customer billing determinants. This method will reflect the revenue they would have collected if the 2021 distribution rates had been in place.

*The Effective Date and the Time Period for Collection of 2021 Deferred Amounts Through Customer Rates*

The AUC reviewed multiple collection period scenarios provided by the ATCO Utilities. It determined that the collection by each utility should begin as soon as possible to balance the effects of rate shock and intergenerational inequity and to reduce carrying costs. In response to an AUC information request, the ATCO Utilities provided estimated customer bill impacts for different collection scenarios over different time periods between 2020 and 2025.

Each of the ATCO Utilities was directed to, as part of their 2022 annual PBR rate adjustment filings, submit their individual plans to implement and collect the 2021 deferred amounts starting January 1, 2022. They were further directed to provide the forecasted customer rate impacts and any rate shock mitigation proposals to ensure there is no rate shock on customer bills as a result of the distribution rate increases over the two-year periods starting January 1, 2022, and January 1, 2024.

While it preferred that the 2021 deferred amounts be collected over a two-year period, the AUC noted that, because of rate shock mitigation, the collection period might need to be longer upon review of each of the ATCO Utilities Implementation plans.

*Carrying Costs Applied to the 2021 Deferred Amounts*

In situations such as the one in this application, where there is a lag between the time when costs are incurred, and when those costs are recovered through the implementation of the necessary rate adjustment, the AUC can approve the payment of interest on adjustments of utility costs or rates.

The AUC determined that applying the interest rate according to Rule 023 to determine the carrying costs is reasonable and an established method. The AUC had approved this method for the calculation of similar deferred amounts in previous PBR rate adjustment decisions. The ATCO Utilities were directed to apply Rule 023 to calculate the carrying costs for their respective 2021 deferred amounts as part of their respective 2022 annual PBR rate adjustment filings.

AUC Order

The ATCO Utilities were ordered to submit their respective individual plans to implement and collect the 2021 deferred amounts beginning on January 1, 2022, as part of its 2022 annual PBR rate adjustment filing.

***ATCO Electric Ltd. Decision on Preliminary Question Application for Review of Decision 24964-D02-2021 2020-2022 General Tariff Application,* AUC Decision 26483-D01-2021**
***Electricity - Review and Variance***

In this decision, the AUC denied the application from ATCO Electric Ltd. (“AE”) for a review and variance of findings in Decision 24964-D02-2021 regarding inflation rates for in-scope labour for 2020 and 2021. Decision 24964-D02-2021 (the “Decision”) related to AE’s 2020-2022 general tariff application (“GTA”).

The AUC review process has two stages. In this proceeding, the AUC considered the first stage in which it determined whether an error of fact, law, or jurisdiction was made by the panel of the Decision.

Section 4(d)(i) Grounds – Errors of Fact, Law or Jurisdiction

In the Decision, the AUC approved in-scope labour inflation rates of 1.90 percent for 2020 and 1.75 percent for 2021. AE had applied for in-scope labour increases of 2.25 percent in 2020 and 2.75 percent in 2021. In the application for review, AE submitted that the hearing panel failed to apply or incorrectly applied the correct legal test, under Section 122 of the *Electric Utilities Act* (“*EUA*”), regarding the rights of AE to recover its reasonably and prudently incurred costs. AE argued that paying amounts that legally must be paid as a result of the binding labour arbitration process is reasonable and prudent. Accordingly, it argued that section 122 required that the AUC approve these costs as just and reasonable. Denial would deprive AE of a reasonable opportunity to recover its approved fair return on equity.

AE further argued that in the Decision, the AUC panel had erred in relying on hindsight and irrelevant information. Namely, AE criticized the AUC’s reliance on information such as wage settlements by AltaLink Management Ltd. and by ENMAX and uncertainties surrounding the COVID-19 pandemic that was not available to the labour arbitrator.

*AUC Review Panel Findings*

The Review Panel, in this proceeding, framed the issue as to whether the hearing panel was statutorily bound under Section 122 of the *EUA* to apply AE's asserted prudence methodology in its review of the applied-for inflation rates for in-scope labour for each of 2020 and 2021.

In this case, section 121(4) of the *EUA* places the burden on AE to establish that its costs are reasonable. The AUC noted that sections 121 and 122 of the *EUA* describe what the AUC is required to consider when evaluating a tariff. Section 122 gives the AUC express discretion over the methodology to be used in setting rates and may make use of a variety of analytical tools and evidence in assessing the justness and reasonableness of a utility's proposed rates so long as the ultimate rates it sets are just and reasonable to both consumers and the utility. The AUC determined that the labour arbitration decision does not trump the AUC's power to set just and reasonable utility rates.

The AUC determined that the panel in the Decision reasonably assessed AE's inflation rates for in-scope labour for each of 2020 and 2021 to find that it was reasonable on its face and on a balance of probabilities. AE did not show, either on a balance of probabilities or apparent on the face of the Decision, that an error in fact, law or jurisdiction exists on this ground that could lead the AUC to materially vary or rescind the Decision.

In answering the preliminary question, the AUC Review Panel found that AE did not meet the requirements for a review of the Decision and the application for review was dismissed.

***ATCO Electric Ltd. Narrows Point Power Plant Decommission and Salvage,*** **AUC Decision 26479-D01-2021**
***Electricity - Facilities***

In this decision, the AUC approved the application from ATCO Electric Ltd. ("AE") to discontinue operation and to decommission and salvage the Narrows Point Power Plant (the "Power Plant"). The AUC declined to strike the isolated generating units comprising the Power Plant from Part A to the schedule of *the Isolated Generating Units and Customer Choice Regulation.* ("*IGUCCR*"). The AUC found that section 27 of that regulation, which would require striking the isolated generating units, does not apply in the circumstances of this application.

Discussion

The Power Plant served the isolated community of Narrow Point near Slave Lake, has a generating capacity of 201 kilowatts and is comprised of four diesel generating units.

AE stated that increasing capital maintenance costs brought a need to connect the community to the Alberta Interconnected Electric System ("AIES"), which followed in July 2020. As a result of the connection, the Power Plant was no longer needed. Decommissioning of the Power Plant was scheduled to start as early as January 2022, with a targeted completion date of March 2023.

The AUC found that the decommissioning application met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments*. The AUC found the decommissioning and salvage of the Power Plant to be warranted because the community that it served is now connected to the AIES. It further accepted AE's commitment to remediate and reclaim the Power Plant site to a condition deemed acceptable to Indigenous Services Canada, Alberta Environment and Parks, and the Canadian Council of Ministers of the Environment guidelines.

The AUC determined that Section 27 of the *IGUCCR* does not apply to the circumstances described in AE's application. Section 27 applies where an isolated generating unit will be replaced or an additional unit is required, while in this case, the units are only being decommissioned. Accordingly, the AUC found it could not approve striking the four generating units of the Power Plant from Part A of the schedule to the *IGUCCR.* As AE further stated that it intended to sell the generating units of the Power Plant, the AUC determined that they would be struck from Part A of the schedule under section 20 or 21 of the *IGUCCR* when the requirements of either of those sections are met.

### *ATCO Gas and Pipelines Ltd. Pipeline Acquisition from Pioneer Pipeline Inc., AUC Decision 25937-D01-2021*

***Gas - Facilities***

Applications

In this decision, the AUC approved applications from ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. (“ATCO Pipelines”), to (i) acquire an existing pipeline and associated facilities from Pioneer Pipeline Inc. (“Pioneer”) and integrate them into the integrated Alberta natural gas transmission system; and (ii) include the acquisition costs in its revenue requirement. ATCO Pipelines was directed to revise its 2021-2023 revenue requirement to reflect the approval of the acquisition of the Pioneer pipeline. The AUC also approved a 2021 revenue requirement of $7.75 million for ATCO Pipelines’ portion of the Pioneer pipeline.

ATCO Pipelines agreed to buy approximately 130.3 kilometers of existing 508-millimeter outside diameter high-pressure sweet natural gas pipeline from Pioneer. ATCO Pipelines requested that the AUC include acquisition costs of $265.66 million (comprised of the purchase price of $255 million and additional capital expenditures related to system and integrity improvements) into its rate base and revenue requirement. ATCO Pipelines stated that after incorporating the subsequent transfer to NOVA Gas Transmission Ltd. (“NGTL”) of approximately 29.9 kilometers of the Pioneer pipeline, the combined 2021 revenue requirement associated with its acquisition includes an ATCO Pipelines revenue requirement of $7.75 million and an NGTL revenue requirement of $1.21 million.

ATCO Pipelines submitted that purchasing the Pioneer pipeline would be the best solution for increasing the ability of the Alberta System to meet growing natural gas demand in the Wabamun area, including providing the capacity to meet a contract for new delivery services. It added that a delivery customer had approached NGTL with a request from TransAlta to provide new firm transportation delivery (“FT-D”) service of 351 terajoules per day to the Keephills and Sundance power plants.

Determination of Project Need Including Viable Alternatives

The AUC determined that the request from ATCO Pipelines without consideration of alternative options to deliver the requested service was reasonable in the circumstances. The option recommended by ATCO Pipelines acknowledges that the incremental FT-D and FT-R contracts are contingent upon the acquisition of the Pioneer pipeline.

ATCO Pipelines submitted that its proposed acquisition would provide an economic benefit of approximately $37.3 million to the interconnected Nova Gas Transmission Ltd. and ATCO Pipelines (collectively, the “Alberta System”). The AUC accepted NGTL’s needs assessment, performed following the approved Integration Agreement procedures, to conclude that without the Pioneer pipeline acquisition, the capacity of the existing Alberta System would be inadequate to meet the incremental contract demand. The AUC found that ATCO Pipelines had demonstrated the need for the acquisition.

Prudence of Acquisition Costs and Revenue Requirements

Interveners raised concerns with the purchase price of the Pioneer pipeline, as it exceeded the net book value by $34.7 million. Further problems included that the FT-D contract term is only 15 years, while the depreciation life of the Pioneer pipeline is 67 years.

The AUC was satisfied that the prudence of the acquisition and the negotiated purchase price is supported by the forecast that the cumulative present value (“CPV”) of the revenue generated exceeds the CPV of the revenue requirements. The AUC found that the CPV of $269.7 million in direct revenues from the NGTL contracts would exceed the CPV of the revenue requirement for the pipeline and associated projects over the 2021-2040 period by more than $37 million. Consequently, a net benefit to the Alberta System ratepayers was forecast from the transaction.

The AUC also found that the costs, including internal and legal costs, were reasonable and necessary to allow ATCO Pipelines to thoroughly review the contract details and ensure the integrity of the Pioneer pipeline.

The AUC was also satisfied that the requested inclusions in the revenue requirements were reasonable and found no persuasive evidence of intergenerational risk to ratepayers that would result from the purchase of the Pioneer pipeline. The AUC found that ATCO Pipelines established that the costs of the pipeline would be recovered over the life of the asset, with revenues projected to exceed the revenue requirements associated with the purchase price, in the absence of considering greenhouse gas reduction legislative impacts on the economic life of the Pioneer pipeline.

Summary of AUC Findings

The AUC concluded that the pipeline acquisition is in the public interest. The AUC directed that ATCO Pipelines revise its 2021-2023 revenue requirement to reflect the approval of the purchase of the Pioneer pipeline. The AUC further approved a 2021 revenue requirement of $7.75 million for ATCO Pipelines' portion of the Pioneer pipeline.

***ATCO Gas and Pipelines Ltd. Application for a Pipeline Licence Transfer from NGTL to ATCO Pipelines,* AUC Decision 26461-D01-2021**

***Gas – Facilities***

In this decision, the AUC approved the application from ATCO Gas and Pipelines ("ATCO Pipelines") to transfer the Coaldale Lateral Pipeline (the "Pipeline") from NOVA Gas Transmission Ltd. ("NGTL") to ATCO Pipelines.

Introduction and Background

In its application to transfer the 4.9 kilometer long pipeline, ATCO Pipelines submitted that the pipeline delivers gas to ATCO Pipelines' downstream customers and that it has no direct connection to NGTL's pipelines. The pipeline is located within ATCO Pipelines' footprint as defined in the Integration Agreement between ATCO Pipelines and NGTL.

The proposed transfer would require no additional upgrades and have no impact on the existing pipeline system's continued operation. ATCO Pipelines agreed to purchase the Coaldale Lateral Pipeline for $222,661, which was based on the net book value and is subject to minor adjustments at the time of closing and transfer.

The CER granted conditional approval for NGTL to sell the Pipeline to ATCO Pipelines in Order MO-004-2021. ATCO Pipelines submitted that, at the time of the application, there were no issues or objections outstanding from the completed consultation with potentially affected landowners and occupants.

AUC Findings

The AUC agreed that, as the Pipeline is connected only to ATCO Pipelines' facilities and the license transfer would allow single-party operation and maintenance for the subsystem, the applied-for license transfer would eliminate inefficiencies for ATCO Pipelines and NGTL. The AUC further found that the transfer is consistent with the geographic service area concept. ATCO Pipelines had sufficiently established the need for the pipeline transfer.

The AUC determined that the proposed pipeline transfer would be in the public interest. It further noted that in this decision, it did not assess the prudence of this addition to the rate base or the impact on the rates of ATCO Pipelines. These matters may be examined in ATCO Pipelines' next general rate application. The AUC approved the applied-for pipeline license transfer.

***ATCO Gas and Pipelines Ltd. Pipeline Transfer to NOVA Gas Transmission Ltd., AUC Decision 26189-D01-2021***

***Gas - Facilities***

In this decision, the AUC approved applications from ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd., for the sale and transfer, to NOVA Gas Transmission Ltd. ("NGTL"), of a 29.9-km segment of the Pioneer Pipeline Inc. pipeline and associated facilities that are within the NGTL geographic service area, and a request to amend the existing pipeline licence.

In considering this application under subsection 26(2)(d) of the *Gas Utilities Act* ("*GUA*"), the AUC typically applies a "no-harm" test that considers the proposed transaction in the context of both potential financial impacts and service level impacts to customers.

<u>AUC Findings</u>

In Decision 25937-D01-2021, the AUC approved ATCO Pipelines' application to acquire the approximately 130.3 km-long, high-pressure sweet natural gas Pioneer pipeline and directed ATCO Pipelines to true-up its revenue requirement to reflect the approval of the acquisition in its next rates application. In doing so, the AUC acknowledged that this was necessary to ensure that the existing integrated Alberta System (defined below) has the capacity to meet incremental contract demand and that the purchase price of the pipeline and other acquisition-related costs were prudent.

ATCO Pipelines requested that the facilities of the proposed transfer be exempt from subsection 26(2)(d) of the *GUA*. Alternatively, ATCO Pipelines requested approval to transfer that portion of the pipeline to NGTL, according to subsection 26(2)(d) of the *GUA.* The AUC found that granting the requested approval is appropriate in the circumstances. The AUC noted that granting the declaration that subsection 26(2)(d) does not apply to "any transaction" concerning the sale of the pipeline segment may allow ATCO Pipelines to alter a material term of the proposed transaction without informing or having approval from the AUC. The alternative was found to be the better solution, as it ensures that the terns of the proposed transaction on which the AUC relied would remain unchanged. Accordingly, the AUC found that it was in the public interest to approve the transfer to NGTL, pursuant to subsection 26(2)(d) of the *GUA*.

Because the integrated NGTL and ATCO pipeline systems (the "Alberta System") are operated collaboratively, and because both pipelines are subject to regulatory oversight, the AUC was satisfied that the transfer would not affect service quality or reliability and that there would be no negative impact on ratepayers.

Accordingly, the AUC found that the proposed transfer to NGTL of the 29.9 km portion of the existing Pioneer pipeline meets the no-harm test, is consistent with the Integration Agreement, and supports the overall benefits of integration.

<u>Decision</u>

The AUC approved the transfer from ATCO Gas and Pipelines Ltd. to NGTL under subsection 26(2)(d) of the *GUA*. The AUC also approved the amendment to Licence 60496 pursuant to Section 11 of the *Pipeline Act* and Section 4.1 of the *GUA.*

***Capital Power Generation Services Inc. Genesee Unit 3 Power Plant Alteration,* AUC Decision 26457-D01-2021**

***Electricity - Facilities***

In this decision, the AUC approved the application from Capital Power Generation Services Inc. ("Capital Power") to alter the Genesee Unit 3 Power Plant.

Capital Power applied for the alteration to allow for the construction and operation of a project for carbon capture through a letter of enquiry. The proposed alterations will include the installation of a new fuel gas inlet piping from the G3 stack to the Genesee Carbon Conversion Centre, a new 13.8-kilovolt switchgear section in the Genesee Generating Station’s existing switchgear, and installation of a new transformer. In its application, Capital Power included a participant involvement program that confirmed that there were no outstanding objections from adjacent landowners. Further, a letter from Alberta Environment and Parks was included, which confirmed that the project would not require an amendment to the Genesee Generating Station’s *Environmental Protection and Enhancement Act* approval.

AUC Findings

The AUC was satisfied that the changes were of a minor nature, would not negatively impact the environment, that no person was directly or adversely impacted and that the participant involvement program met the requirements of Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments.* The AUC further found that the information provided by Capital Power regarding the need, nature, extent, land affected, land ownership, and the timing of the alterations met the requirements of Section 12 of the *Hydro and Electric Energy Regulation*.

The AUC approved the requested alterations and noted that a new approval of the Genesee Unit 3 Power Plant was not required.

***Capstone Infrastructure Corporation Buffalo Atlee Wind Farm, AUC Decision 25100-D01-2021***
***Wind - Facilities***

In this decision, the AUC approved applications from Capstone Infrastructure Corporation (“Capstone”) filed on behalf of BA1 Wind GP Corp., BA2 Wind GP Corp., and BA3 Wind GP Corp. to construct and operate Buffalo Atlee Wind Farm 1 (“Buffalo Atlee 1”), Buffalo Atlee Wind Farm 2 (“Buffalo Atlee 2”), and Buffalo Atlee Wind Farm 3 (“Buffalo Atlee 3”) and to connect them to the FortisAlberta Inc. electric distribution system at three locations.

Introduction

This project was acquired by Capstone from MAXIM Power Corp.(“MAXIM”), who had received approval for Buffalo Atlee 1 and 3 but added Buffalo Atlee 2 as a third phase of the project and reduced the number of turbines at Buffalo Atlee 1 and 3. As there was no buildable area application for Buffalo Atlee 2 filed by either MAXIM or Capstone, the AUC considered its previous Approval 22755-D02-2018 expired and rescinded. In this proceeding, the AUC considered Capstone’s applications as new. This also gave Capstone an opportunity to further mitigate the environmental effects of the project that had been previously pointed out.

Interveners

The AUC received statements of intent to participate from Dustin Aebly; Danny Aebly; Special Area No. 2; Jenner Wind 1 GP Inc., on behalf of Jenner 1 LP (Jenner 1); and Jenner Wind LP (Jenner 1 and Jenner Wind LP are collectively referred to as the Jenner Entities). The Jenner Entities have an approved by not yet constructed Jenner Wind Power Project (Jenner 1) and two proposed Wind Power Projects (Jenner 2 and Jenner 3). Standing was granted to Dustin Aebly, Danny Aebly, and the Jenner Entities and the AUC held a written hearing to consider the applications. The AUC also granted Special Area No. 2 (the rural municipality governed by the Special Areas Board and within which the project would be located), full rights to participate in the hearing, but noted that it would not be eligible to make a local intervener costs claim for its participation.

Concerns of Special Area No. 2 and Adjacent Landowners and Occupants

Special Area No. 2 raised the concern that the project’s design does not meet the minimum setback requirements of *Special Areas – 2, 3 and 4 Land Use Order Ministerial Order No. MSL:007/15* (the “*Land Use Order*”) and that since there is no written agreement with the affected landowner, the project would not receive a municipal development permit.

Although the AUC noted that it could consider Special Area No. 2's statement, it did not file any evidence or argument in this proceeding for the AUC to review.

Dustin Aebly stated that Capstone did not follow the minimum 550-meter setback between turbines and the boundary of his properties as per the *Land Use Order* and that this would affect his cattle operations. Cattle grazing, decreased land values, noise pollution, groundwater, shadow flicker, and the effect on birds of prey that help control rodents were also on his list of concerns. Similarly, Danny Aebly is a landowner of adjacent lands, one of which is 200 to 300 meters directly south of Turbine T3 of Buffalo Atlee 2. He indicated that he did not consent to that location and that he is concerned about cattle grazing and property values.

The AUC noted that neither Dustin Aebly nor Danny Aebly filed evidence or argument to substantiate their respective concerns. Therefore, the AUC could not reasonably draw any conclusions or make any findings regarding the project's adverse effects on their concerns.

In its response to Special Area No. 2, Capstone filed considerable argument demonstrating that Buffalo Atlee 1 is in compliance with the *Land Use Order*, the consent of Dustin and Danny Aebly is not required, and that in any event, having regard to Section 619 of the *Municipal Government Act*, and *Borgel v Paintearth (Subdivision and Development Appeal Board)*, outstanding issues with the municipal planning process are not an impediment to their applications. The AUC stated that the issue regarding setbacks and consent is up to the Special Areas Board to decide, and the AUC does not have authority to enforce the setback or reduce its requirements.

Participant Involvement Program

Capstone retained LandSolutions LP to conduct the consultation process for the project. Their participant involvement program included information packages mailed to community stakeholders, phone calls with local residents and stakeholders, one-on-one meetings, and two public open houses.

The Jenner Entities claimed that Capstone failed to meaningfully and sufficiently engage with them regarding their concerns. Capstone replied that both the Jenner Entities and their parent company Potentia Renewables Inc. received all of the mailouts, and asserted that their involvement in the process was for financial gain.

The AUC was satisfied that Capstone met all applicable Rule 007 requirements for participant involvement. They were not persuaded by the Jenner Entities' concerns and did not find that the fact Capstone was unable to resolve them is of concern.

Wake Effect

The Jenner Entities filed a wake loss study report prepared by Westwood Professional Services Inc. ("Westwood"). Westwood stated that it modeled the wake effect of the Buffalo Atlee Wind Farm on the Jenner 1 Project. Westwood noted that when Jenner 2 and Jenner 3 were not included, the Buffalo Atlee Wind Farm would produce a total deficit in the Jenner 1 annual energy production of 2,613.1 megawatt hours per year (MWh/yr), which represents approximately 0.5 per cent of the Jenner 1 total energy production. The Jenner Entities stated that the present value of the loss of revenue resulting from the deficit would be greater than $1.5 million over the lifetime of the Jenner 1 Project.

However, Capstone also stated that based on the predominant wind direction, the Buffalo Atlee Wind Farm would not be located upwind of the Jenner 1 Project. It submitted that if the AUC has the jurisdiction to consider wake effect, the Commission must consider that the Buffalo Atlee Wind Farm would be more adversely affected by wake from the Jenner Projects than the Jenner Projects would be by wake from the Buffalo Atlee Wind Farm. Capstone put forward evidence of a 1.7 per cent or 3,297 MWh/yr adverse wake effect impact on the Buffalo Atlee Wind Farm.

The AUC also stated that although they appreciate the parties' respective submissions on legal rights associated with wake effect from other jurisdictions, there was at the time no regulatory requirement to address wake effect on adjacent wind projects in Canada. The Jenner Entities failed to establish that either a public interest associated with, or a legal right to protection from wake effects *vis-à-vis* proximate wind developers exists in Alberta.

Accordingly, it was not necessary for the AUC to consider the evidence offered by the parties on the necessity for or the reasonability of the mitigation measures requested by the Jenner Entities, or whether symmetrical mitigation should be considered.

Noise

Capstone retained Golder Associates Ltd. (“Golder”) to perform a noise impact assessment (“NIA”) for the project. Golder predicted that the project would comply with Rule 012 and that there would be no low-frequency noise issues related to the project. The Jenner Entities retained RWDI Consulting Engineers and Scientists (“RWDI”) to review that same NIA. Dustin Aebly also expressed concerns about noise but did not provide any evidence or argument.

There was some significant back-and-forth regarding the fact that the NIA established that the permissible sound level was 40 decibels (within acceptable parameters) when in fact, it was measured at 40.3 decibels and rounded down to 40. There was a dwelling identified as R1 in the NIA that RWDI suggested may be in an area with too high a noise level. Capstone submitted that the Buffalo Atlee Wind Farm turbines would use special operating modes to mitigate high noise levels. As such, the following condition to approval was imposed:

- The approval holder shall implement the required operating modes for the project turbines, as described in the project noise impact assessment, as of the date the project turbines commence operation.

The higher than assumed noise level at R1 lead to the following condition to approval being imposed for Buffalo Atlee 1:

- BA1 Wind GP Corp. shall conduct a post-construction comprehensive sound level survey, including an evaluation of low-frequency noise, at Receptor R1. The post-construction comprehensive sound level survey must be conducted under representative conditions and in accordance with Rule 012: Noise Control. Capstone shall file a report with the AUC presenting the measurements and summarizing the results of the post-construction comprehensive sound level survey within one year after the Buffalo Atlee 1 Wind Farm commences operations.

The Jenner Entities stated that the higher noise levels of the Buffalo Atlee Project meant that their own noise parameters were greatly reduced. The AUC noted that that is simply a part of doing business.

Environmental Effects

AECOM Canada Ltd. (“AECOM”) was retained by Capstone to complete an environmental evaluation of the Buffalo Atlee Wind Farm. In a renewable energy referral report issued by Alberta Environment and Parks (“AEP”) on November 20, 2019, AECOM assessed that the project has an overall high risk for wildlife and wildlife habitat based on the project being situated on native grassland and the high occurrence of species at risk, their habitat features, and their dependence on native grassland.

On March 23, 2020, the AUC put this proceeding in abeyance to allow Capstone to mitigate these risks. AECOM subsequently prepared an amendment to their original evaluation proposing a revised layout for the project as well as additional fieldwork. As a result of the new layout, the direct effects to native grassland were reduced by 56 percent, would infringe on the setbacks of five fewer non-temporary wetlands, and that all infrastructure within setbacks for raptor species nests was removed. As a result, the project went from high risk to a moderate risk ranking.

The AUC was satisfied that the project’s potential effects on wildlife and wildlife habitat, including the risk associated with impacts to native grassland, will be adequately mitigated with the diligent implementation of Capstone’s various commitments and through the imposition of the conditions stipulated

Conclusion

Subject to the conditions outlined in the decision the AUC found that Capstone satisfied the requirements of rules 007 and 012, and approval of the project is in the public interest having regard to the social, economic, and other effects of the project, including its effect on the environment.

***Direct Energy Regulated Services 2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement,* AUC Decision 26207-D01-2021**
*Electricity - Rates*

In this decision, the AUC approved an application from Direct Energy Regulated Services ("DERS") requesting approval of a negotiated settlement agreement ("NSA") reached with respect to its 2020-2022 default rate tariff ("DRT") and regulated rate tariff ("RRT") application.

Background

DERS performs the natural gas DRT and electricity RRT functions in the service territories of ATCO Gas and Pipelines Ltd. ("ATCO Gas") and ATCO Electric Ltd., respectively. On December 21, 2021, DERS filed an application for approval of its DRT and RRT revenue requirements and associated rates for 2020-2022. Following the notice of application issued by the AUC, the Consumers' Coalition of Alberta ("CCA") and the Office of the Utilities Consumer Advocate ("UCA") filed submissions.

On January 29, 2021, the AUC directed parties to proceed to mediation in an effort to reach a settlement of the application and to conclude the mediation no later than April 1, 2021. Following a notification from DERS on April 1, 2021, that a verbal agreement had been reached, DERS filed the NSA on April 23, 2021. The NSA consisted of a signed agreement between the parties and six appendixes to the signed agreement.

Statutory and Rule Requirements for Approval of a Negotiated Settlement Agreement

Section 8 of Rule 018: *Rules on Negotiated Settlements* sets out rules and requirements associated with negotiated settlements. Rule 018 requires that the AUC assess whether the settlement results in rates and terms and conditions that are just and reasonable and intervene if it determines that a unanimous settlement is patently against the public interest or contrary to law.

Fairness of the Negotiated Settlement Process

The AUC found that parties had enough opportunity and information to participate meaningfully in the negotiated settlement process. Further given the well-developed record, the period of two months of negotiations, along with the fact that no concerns were raised regarding the negotiated settlement process and the involvement of the two qualified mediators in the negotiations, as directed by the AUC, the AUC was satisfied that the negotiated settlement process was fair.

Public Interest

The AUC is required to determine if the NSA is in the public interest. This includes a determination of whether the resulting rates are just and reasonable. Section 8(2) of Rule 018 required the AUC to intervene if it determines that a unanimous settlement is patently against the public interest or contrary to law.

The AUC noted that the NSA represents a unanimous agreement reached through a negotiation process involving both the CCA and the UCA. This fact, and the fact that the CCA and the UCA collectively represent the interests of a majority of DERS' RRT and DRT customers, supported the AUC's finding that the NSA is in the public interest.

*Analysis of Five Principal Aspects in the NSA*

(a) Revised revenue requirement forecasts, inputs and assumptions;

The AUC noted that the DRT and RRT revenue requirements are based on forecast costs and revenues. Many of the inputs used to calculate the revised revenue requirements were the subject of updated information provided through DERS' IR responses. DERS stated that the net result is a reduction to aggregate DRT and RRT revenue requirements relative to the original application. The AUC noted the reduction to aggregate DRT and RRT revenue requirements and that the rates in the NSA are derived from the agreed-upon revenue requirements by an allocation method that had been approved by the AUC most recently in Decision 24237-D01-2019.

The AUC determined that the increase in rates, compared to 2019 approved rates, resulting from the revenue requirements in the NSA is reasonable because the impact on rates is minimal.

(b) Bad debt deferral account and late payment charge deferral account;

DERS and interveners agreed to implement deferral accounts for bad debt and late payment charge. They further agreed that the forecast of $25,072,500 for 2021 and $21,062,000 for 2022 on bad debt and late payment charge would be subject to deferral account treatment.

The bad debt deferral account includes an incentive mechanism that results in DERS carrying some risk. The mechanism limits DERS' risk exposure to exceptionally high bad debt and allows DERS to profit from and share the benefits of exceptionally low bad debt. The incentive mechanism also benefits customers by shielding them from high bad debt.

The AUC recognized that differing assumptions factoring into bad debt forecasts would lead to wide-ranging results. The AUC considered that the incentive mechanism, which provides both risk or reward to DERS and its customers, is an appropriate solution to approach the uncertain outcomes.

(c) Revised DRT and RRT revenue requirements and Revised DRT and RRT rate schedules

DERS advised that some of the revised revenue requirement inputs are interdependent, and because they were agreed to in the aggregate for both DRT and RRT, they are not in all cases consistent with the corresponding figures in the revised revenue requirement models. In the case of any inconsistency, the parties agreed that the figures in the revised revenue requirement models prevail.

The AUC considered the revised DRT and RRT 2020 rates to be final and that 2021 and 2022 rates are final, subject to the finalization of the bad debt and late payment charge deferral accounts.

(d) Commitments for future action.

The AUC acknowledged that the parties agreed to future actions, including actions to ensure that information on bad debt expense and late payment charge revenue is up to date and that all parties are informed of up-to-date information.

*Findings on Rates for Gas Cost Flow-Through Rate*

The DRT energy-related rates affecting DERS' gas cost flow-through rate ("GCFR") filings are the fixed monthly dollar amount related to procurement labour, and the working capital, credit charges, energy-related bad debt and late payment charge are on a $/GJ basis. In addition to the GCFR, DERS applies for approval of Rider F in its required monthly filings. One of the inputs to Rider F is the DRT return margin, which is a rate requested in DERS' non-energy applications.

The AUC reviewed the DRT energy-related rates and approved these rates as inputs to DERS' monthly gas filings, on a final basis, with certain exceptions. The Commission considered that the DRT energy-related rates not subject to deferral account treatment are final for 2020, 2021 and 2022. The DRT energy-related rate is final for 2020, and the 2021 and 2022 rates are approved on a final basis, subject to the finalization of the bad debt and late payment charge deferral accounts.

*Approval of the NSA*

The AUC found that the settlement will result in just and reasonable rates and, accordingly, approved the NSA.

Matters Outside of the NSA

*Finding - Compliance with Decision 24237-D01-2019*

In Decision 24237-D01-2019, the AUC issued directions requiring DERS to file further information, detail, and an explanation regarding its cost allocation methodology in certain areas, what costs are included in which cost categories. DERS was further directed to provide a more detailed variance reporting on prior years' actual and approved corporate service costs and what corporate services DERS required, and how these were allocated.

The AUC was satisfied that additional information submitted by DERS in response to these directions clarified outstanding issues and uncertainties. Accordingly, the AUC found that DERS complied with the directions.

*True-up of Interim Rates*

As DERS operated under approved interim rates in 2020 and continues to operate under interim rates in 2021, the interim rates should be trued up to the final rates for 2020 and 2021 approved by the AUC in this decision. DERS was directed to file a separate application for the true-up of the approved 2020 and 2021 rates after it has completed billing on interim rates for service up to June 30, 2021.

***Direct Energy Regulated Services Acknowledgment of the Filing of Changes in the Forecast Load Methodology and Approval of Revisions to the 2020-2022 Energy Price Setting Plan,* AUC Decision 26545-D01-2021**

***Electricity - Rates***

In this decision, the AUC approved the application from Direct Energy Regulated Services ("DERS") for changes in DERS' forecast load methodology included in its 2020-2022 energy price setting plan ("EPSP").

Background

As a regulated rate option ("RRO") provider, DERS is required to file monthly electric energy rates with the AUC. These rates are determined pursuant to the *Electric Utilities Act*, in accordance with the *Regulated Rate Option Regulation* and the AUC-approved EPSP. DERS' approved EPSP establishes the pricing of electricity for RRO customers in the distribution service territory of ATCO Electric Ltd. ("AE").

In the application, DERS submitted that as approved, the 2020-2022 EPSP permits forecast methodology improvements to be implemented through acknowledgment filings. DERS provided the Consumers' Coalition of Alberta ("CCA") and the Office of the Utilities Consumer Advocate ("UCA") with a courtesy copy of the application.

Changes in DERS' Forecast Load Methodology in the 2020-2022 EPSP

DERS indicated that the change to the forecast load methodology involves amending the determination of the line loss factors ("LLFs") for every customer rate class, which are a component of the distribution line loss ("DLL") percentages for every rate class.

DERS indicated that it discovered that AE's average secondary distribution system line losses have increased from approximately five per cent to six per cent. DERS described this increase as an unforeseen consequence of an approved change to AE's price schedules in Decision 24747-D01-2021. The changes to the forecast load methodology were required to repair a persistent forecasting error to the monthly RRO load forecast, resulting from the increase in LLFs.

DERS proposed changes to Section 1 of Schedule 1 and Section A(4)(b) of Schedule C of the 2020-2022 EPSP to accommodate the increase in secondary distribution system line losses.

The AUC agreed that the proposed amendments are an improvement that would result in more accurate monthly electric energy rates than would be the case if DERS continued to use the currently approved forecast load methodology. The AUC accepted the filing for acknowledgment with respect to the 2020-2022 EPSP and approved the revisions to the 2020-2022 EPSP.

Other Matters

The inputs and calculations required to determine the monthly electric energy rates that result from the 2020-2022 EPSP are outlined in the illustrative rate book, which is provided in the Negotiated Settlement Agreement approved in Decision 25818-D01-2021. As a result of this decision, DERS was directed to revise the illustrative rate book to incorporate the amendments to the 2020-2022 EPSP approved by the AUC in this proceeding and file it as a post-disposition document to this proceeding.

### ***ENMAX Power Corporation 2021-2022 General Tariff Application Negotiated Settlement Agreement and Excluded Matters,* AUC Decision 25726-D01-2021**

*Electricity – Rates*

In this decision, the AUC approved the negotiated settlement agreement ("NSA") applied for by ENMAX Power Corporation ("EPC") regarding its 2021-2022 general tariff application ("GTA"). Regarding issues excluded from the NSA, the AUC denied EPC's proposed depreciation and Enhanced Asset Management Strategy ("EAMS") initiative costs.

Negotiated Settlement

The only matters regarding EPC's 2021-2022 GTA that were excluded from the NSA are depreciation expense and EAMS.

*Fairness of the Negotiated Settlement Process*

The AUC evaluated whether the negotiated settlement process ("NSP") that resulted in the NSA was fair. As the Consumers' Coalition of Alberta ("CCA"), the Utilities Consumer Advocate ("UCA"), and EPC each submitted correspondence confirming the fair and open negotiations, the AUC accepted that the NSP had been conducted fairly.

*Public Interest*

EPC submitted that the NSA for its 2021-2022 GTA would result in just and reasonable rates and that the settlement aligns with the public interest and abides by all applicable law. EPC further submitted that the NSA meets all the requirements of Rule 018. EPC provided that, in summary, the parties agreed to reductions to the 2021-2022 GTA totaling $8.1 million. The revenue requirement for 2021 was reduced by $2.44 million, with the largest reduction representing a $0.81 million reduction applied to operations and maintenance ("O&M") shared services. The 2022 revenue requirement was reduced by $5.67 million, with the largest reduction being a $2.59 million reduction applied to the Capital Substation 45.

The AUC noted that the NSA represents a unanimous agreement reached as a result of a successful negotiation that typically reflects a number of compromises of different interests and positions of the parties. The signatories to the NSA represent a constituent group of Albertans that has historically participated in the testing of EPC's general tariff applications, which supports a finding that the NSA is in the public interest.

The AUC was satisfied that the NSA is not patently against the public interest or contrary to law and should result in rates and terms and conditions that are just and reasonable, as required by Section 8 of Rule 018. The NSA was approved as filed.

Excluded Matters

*Depreciation Expense*

EPC requested forecast depreciation expenses for the years 2021 and 2022 in the amounts of $29.2 million and $32.4 million, respectively. EPC stated that in determining its forecast 2021-2022 depreciation expense, it relied on parameters and corresponding depreciation rates approved by the AUC in Decision 2014-347. EPC was unable to provide detailed support for its depreciation expense calculations given reporting limitations of its fixed asset software. Further, EPC was not willing to prepare alternative manual depreciation calculations because “the time and effort required to prepare the analysis requested are beyond the time given for responding to this information request.” EPC stated it would provide the requested calculations at the time of its next depreciation study.

EPC calculated a single weighted average depreciation rate for its total property, plant and equipment, followed by two further weighted average depreciation rates for each of its transmission and general plant groups of assets. While accepting that depreciation expense is a complicated element of the revenue requirement, and in consideration of the depreciation expense amounts at issue, the AUC found that the high-level calculations provided by EPC did not reasonably support its forecast depreciation expense in the current application.

Accordingly, EPC’s forecast depreciation expense for the years 2021 and 2022 were declined and EPC was directed to incorporate its last approved depreciation expense in the amount of $24.1 million (2020) in its revenue requirement for each of the test years at issue. EPC was also directed to ascertain and submit, with its next depreciation study, a detailed plan for how the AUC and parties can test EPC’s depreciation expense calculations between the submission of depreciation studies.

*Enhanced Asset Management Strategy Initiative*

EPC requested $1.65 million in 2021 and $1.69 million in 2022 in incremental O&M costs to undertake a new EAMS initiative, beginning in 2021. Under the initiative, five additional full-time equivalents would be required, and several activities would be undertaken.

The AUC noted that a business case was not provided to support the initiative, and EPC only identified high-level activities to be undertaken. In response to AUC questions, EPC provided a cost-benefit study undertaken in 2019 that identified savings of approximately $6.7 million. As the scope for the EAMS initiative was further refined, an updated cost-benefit analysis was provided that did not identify any savings in the test period. Savings were expected to start occurring in 2023. EPC also estimated that it would incur additional expenditures totaling $1.09 million from 2023 to 2026 for the EAMS initiative, and based on its net present value analysis, the EAMS initiative would break even in 2031.

The AUC was not convinced that the EAMS initiative can be justified based on the cost-benefit analysis provided, particularly as no savings were expected in the 2021-2022 test period. Further, some of the estimated savings would arise from activities unrelated to the main activities being completed under the EAMS initiative. For example, EPC has included standards and estimation improvements as part of the EAMS initiative. The AUC found it unclear how the development of these standards is dependant on or related to the other EAMS activities and was not persuaded that these standards and estimation improvements should be included in the EAMS initiative.

The AUC was not satisfied that EPC provided sufficiently detailed information regarding the comparison and assessment of realized benefits against the costs of the EAMS initiative in the future. The AUC noted that tracking and measuring the outcomes from any new initiative proposed by a utility is needed to ensure that ratepayers are receiving concrete benefits from the initiative. EPC had not provided information to make such an assessment possible. Further, the AUC found it unclear whether EPC’s current asset management practices and tools were sufficient that the AUC could not determine the necessity of reasonableness of increased costs to improve the tools and practices.

Further, the AUC found that evidence regarding the allocation of EAMS initiative costs by EPC between EPC transmission and distribution was inconsistent and conflicting. As a result, the AUC was unable to ascertain the basis on which the costs for the EAMS initiative were allocated and whether the allocations were reasonable.

Accordingly, the AUC did not approve the EAMS initiative. EPC was directed to remove the forecast expenditures associated with the EAMS initiative in its compliance filing to this decision. Should EPC request funding for the EAMS initiative in a future tariff application, the AUC required that EPC provide a full business case.

***FEOC Order Between Fengate Central Utilities Block GP Inc., Fengate Central Utilities Block LP, Heartland Petrochemical Complex Limited Partnership, Inter Pipeline Propylene Ltd., URICA Energy Real Time Ltd. and URICA Asset Optimization Ltd.,* AUC Decision 26543-D01-2021**

***Market Oversight and Enforcement – FEOC***

In this decision, the AUC approved the application from Fengate Central Utilities Block GP Inc. ("Fengate") for the preferential sharing of records that are not available to the public between Fengate, Fengate Central Utilities Block LP ("Fengate LP"), Heartland Petrochemical Complex Limited Partnership ("Heartland"), Inter Pipeline Propylene Ltd. ("Inter Pipeline"), URICA Energy Real Time Ltd. ("URICA Real Time") and URICA Asset Optimization Ltd. ("URICA Optimization").

Introduction and Background

Fengate LP acquired the Heartland Petrochemical Complex Central Utility Block Power Plant ("CUB Power Plant") from Inter Pipeline and entered into a long-term agreement with Inter Pipeline managing the construction and day-to-day operation of the CUB Power Plant. Fengate LP and Heartland had further entered into agreements with URICA Real Time and URICA Optimization to provide advisory and real-time services dispatch and restatement services related to the CUB Power Plant.

Submissions of the Applicant

*Is the Proposed Sharing of Records Reasonably Necessary?*

Fengate explained that neither Fengate LP nor Heartland has adequate personnel or the resources to accept energy or ancillary services dispatch orders in order to manage the output of the CUB Power Plant in the Alberta energy or ancillary services markets on a 24-hour basis. It submitted that URICA Real Time has the expertise and resources to provide these services and or operational energy market services and energy restatements for events at generators as required by the independent system operator ("ISO") rules.

URICA Optimization has the expertise and resources to assist the applicant by helping them to establish and optimize offer strategies for the CUB Power Plant.

Accordingly, Fengate submitted that the sharing of non-public records relating to the CUB Power Plant is reasonably necessary for it to carry out its business related to the CUB Power Plant.

*Fair, Efficient and Openly Competitive Operation of the Electricity Market*

Fengate, on behalf of itself and Fengate LP, and Inter Pipeline, and on behalf of itself and Heartland filed written representation from senior officers of Fengate and Inter Pipeline indicating that the records subject to preferential information sharing will not be used for any purpose that does not support the fair, efficient and openly competitive operation of the Alberta electricity market, including but not limited to the conduct referred to in Section 2 of the *Fair, Efficient and Open Competition Regulation* ("*FEOC Regulation*").

*Offer Control*

The total offer control of Fengate and Fengate LP is 0.4 percent. Heartland and Inter Pipeline's total offer control is 0.4 percent, URICA Real Time's total offer control is zero percent and the offer control of URICA Optimization is 1.0

percent. All of these are less than the offer control limit of 30 percent, as set out in subsection 5(5) of the *FEOC Regulation*.

AUC Findings

Subsection 3(3) of the *FEOC Regulation* authorized the AUC to issue an order permitting the sharing of records on any terms and conditions that the AUC considers appropriate, provided that certain requirements are satisfied. The AUC found that those requirements were met.

The AUC was satisfied that the applicants had demonstrated that the sharing of records was reasonably necessary for Fengate LP and Heartland to carry out their business. It was further satisfied that the subject records would not be used contrary to the fair, efficient and openly competitive operation of the Alberta electricity market, including the conduct referred to in Section 2 of the *FEOC Regulation* and that the applicants would conduct themselves in a manner that would support the fair, efficient and openly competitive operation of the market. The AUC also found that the offer control limit of the entities, both before and after any approval to share records, was less than 30 percent, as required by subsection 5(5) of the *FEOC Regulation*. The AUC also noted that the Market Surveillance Administrator supported the application.

The AUC approved the application subject to conditions.

***FortisAlberta Inc. Distribution-Connected Generation Credit Module for Fortis's 2022 Phase II Distribution Tariff Application,* AUC Decision 26090-D01-2021**
***DCG - Rates***

The AUC determined that the existing distribution-connected generation ("DCG") credit mechanism within the tariffs of ATCO Electric Ltd. ("AE"), ENMAX Power Corporation ("EPC") and FortisAlberta Inc. ("Fortis") will be discontinued. The AUC found that the provision of the DCG credit mechanism does not support just and reasonable ratemaking.

The AUC found that a four-year transition period, set on a declining basis, for the demand transmission service ("DTS") portion of the DCG credit mechanism balances the competing public interest objective in discontinuing it. The rate supply transmission service ("STS") portion of the DCG-related tariff is to be calculated as per usual with no change.

Background

*The DCG Credit Mechanism*

DCG is a supply-side distributed energy resource. As the units are connected to the distribution system, they are required to be smaller than 80 megawatts ("MW"). DCG credits are the payments that AE, EPC, and Fortis provide to DCG connected to their respective distribution systems.

The credits are calculated and paid pursuant to provisions within their respective tariffs. The credits are calculated based on the electrical energy delivered by the DCG to the distribution system and represent the difference between the Alberta Electric System Operator ("AESO") transmission charges the distribution utility must pay with the DCG in operation and the hypothetical charges that would have been incurred if the DCG had not been in operation. The calculated credits are allocated to and recovered from all customers of the distribution utility.

Does the DCG Credit Mechanism Result in Just and Reasonable Rates?

The DCG credit mechanism had previously been approved as part of the rate schedules of AE, EPC and Fortis. The AUC determined that the provision of the DCG credit mechanism does not support just and reasonable ratemaking as it unnecessarily increased the payments ratepayers make for transmission service, and these additional payments are not offset by any proven benefit to ratepayers. The AUC also determined that it promoted an unlevel playing field between generators at the cost of ratepayers.

*What DCG Credits Cost Ratepayers*

The distribution tariff sets the rates to recover the cost of transmission service, which is set by the AESO and recovered through the AESO tariff, and the distribution service. The distribution utility flows the cost of transmission charges through to its load customers through transmission access charges. DCG credits relate to transmission access charges.

If DCG is able to locate on a distribution feeder that also serves load and is able to generate electricity coincident with that load, its operation reduces the flow of energy from the transmission system to the substation. Given the current AESO tariff design and metering locations, these reduced flows serve to lower the metered demand and energy at the substation. Since a considerable portion of the AESO's tariff is collected from its bulk and regional charges on the basis of the monthly coincident peak of the system ("12 CP"), the reduction in metered demand coincident to the peak can significantly reduce the bill received by the distribution utility from the AESO for transmission service due to the presence of DCG on the feeder.

To recover the costs of the transmission system, the AESO employs true-up mechanisms that result in the reduced distribution utility payments being recovered, in subsequent periods, from all ratepayers.

The AUC found that DCG credits represent a high and escalating cost to ratepayers.

*What Benefits DCG Credits Provide Ratepayers*

The AUC determined that there was not enough evidence to support that, in the current regulatory environment, DCG reduces transmission costs in the long term.

The AUC noted that DCG has the potential to reduce transmission costs. But, because the AESO does not consider the presence of DCG in the planning and operation of the transmission system, the AUC determined that there was not enough evidence to support the benefits of DCG.

The AUC further considered the effect of DCG credits on transmission access charges. It found that the way the DCG credit mechanism is structured leads to higher overall transmission access payments for all load customers.

The AUC found that higher payments are a result of the legislative requirement that the AESO manage itself in a manner that does not result in a profit or loss from its operations. The measures that are undertaken by the AESO to meet this requirement result in load customers in aggregate paying for both the total cost of the transmission system and the cost of the DCG credits.

Further, DCG credits result in transmission access charges increasing because the true-up mechanisms and the AESO's revisions to its billing determinant forecast serve to increase the amount of DCG credits paid to DCG. This results in a shortfall in revenue caused by lower billing determinants. The shortfall is accounted for in the AESO's subsequent forecasts, resulting in higher per-unit Rate DTS charges, thus increasing the amount paid to DCG credits for the same amount of energy provided to the system.

The AUC found that because the costs of the transmission system are largely sunk, and the presence of DCG credits is later reconciled in the annual true-up process, ratepayers do not pay a lower bill for avoided transmission access charges due to DCG. This is consistent with the AUC's findings in Decision 22942-D02-2019 and the Final Report for the 2017 Alberta Electric Distribution System-Connected Generation Inquiry. The AUC also found that there are proven costs but no benefits to ratepayers resulting from the DCG credits and that, therefore, the inclusion of DCG credits in a distribution utility's tariffs is not just and reasonable.

*Level Playing Field Considerations*

The AUC considered whether DCG credits are needed to set a level playing field between DCG and other connection and technology configurations.

The AUC considered whether DCG credits support the goal and purpose of the *Electric Utilities Act* ("*EUA*") to provide a fair, efficient and openly competitive electricity market for generation; and to maintain a flexible framework so that decisions on the need for and investment in generation of electricity are guided by competitive market forces. The AUC also considered whether, as argued by supporters of DCG credits, DCG creates similar value additions to the Alberta Interconnected Electric System as industrial system designations, the installation of energy efficiency, or demand response technologies.

The AUC determined that DCG credits harm the competitive market intended by the *EUA* at the expense of customers. It further did not accept the argument comparing DCG to industrial system designation and other technologies because it ignores the fact that these connection and technology configurations are granted differing treatment under the legislation.

The AUC held that the DCG credits create distortionary harm to the wholesale electricity market, impairing the competitive purpose of the *EUA.* In the short run, this results from generators' bidding being influenced by receipt of DCG credits. In the long run, this is because investment choices may be distorted away from potentially less expensive alternatives towards DCG. The result is that the overall cost of generation may be unnecessarily increased. Therefore, and because the AUC found that DCG credits unnecessarily increase the cost to ratepayers without providing them with a proven or quantifiable benefit, the AUC determined that DCG credits should be discontinued.

<u>What Should the Transition Period for DCG Credits Be?</u>

In consideration of the need to balance the interest of ratepayers in saving costs of the DCG credits with the need to foster the confidence of investors in the electricity market to provide a benefit to ratepayers by allowing the implementation of legacy rates, the AUC found a four-year transition period for the Rate DTS portion of the DCG credit mechanism to be reasonable. This transition period, set on a declining basis, balances the competing interests.

Accordingly, AE, EPC and Fortis were directed to calculate the Rate DTS portion of the DCG credits in the same way that they otherwise would have, but then apply a multiplier, starting at 0.8 on January 1, 2022, and decreasing by 0.2 every year on January 1. These utilities were also directed to file their 2022 annual performance/based regulation rate adjustment filings showing the changes directed in this decision.

***Milner Power Inc. Decision on Preliminary Question Application for Review of Decision 26084-D01-2021 Request for Guidance on the Interest Calculation to be Applied to the Proceeding 790 Module C Settlement Process,* AUC Decision 26424-D01-2021**

***Electricity - Review and Variance***

In this decision, the AUC denied the application from Milner Power Inc. ("Milner Power") for review and variance ("R&V") of findings regarding the interest calculation applied to loss factor charges, set out in Decision 26084-D01-2021 (the "Decision"). In those findings, the AUC determined that a simple interest calculation should be applied to loss factor charges recalculated for the period between January 1, 2006, and December 31, 2016 (the "historical period").

This review concerned determinations in Proceeding 790, Proceeding 26084, and the record of this proceeding, Proceeding 26424. Accordingly, for clarity, each AUC panel is referred to as follows:

- The members of the AUC panel who authored the decisions in Proceeding 790 are referred to as the "790 Panel."
- The members of the AUC panel who authored Decision 26084 will be referred to as the "Hearing Panel."
- The members of the AUC panel considering the review application will be referred to as the "Review Panel."

AUC Review Process

In this decision, the AUC considered the preliminary question as part of the review process set out in Rule 016*: Review of Commission Decisions.* Milner Power requested the AUC exercise its authority pursuant to section 6(3)(a) of Rule 016, arguing that the AUC had made errors of fact, law and jurisdiction.

The AUC Acted on False Assumptions

Milner Power stated that the Hearing Panel had erred in its finding that, in Proceeding 790, no party raised the nature of interest awarded by the AUC. Milner Power asserted that this finding of fact was wrong and referenced two separate occasions in Proceeding 790 in which it stated that compound interest had been raised.

It further submitted that the Decision was based on the Hearing Panel's assumption that the Alberta Electric System Operator ("AESO") had not contemplated the calculation of compound interest. Milner Power submitted that this assumption was incorrect because the AESO had made a calculation of this nature prior to submitting its application in Proceeding 26084. Because the Hearing Panel made the finding it did in paragraph 21 of the Decision, Milner argued that the finding must be material and, consequently, it is a material error to be corrected.

The 790 Panel found that it would be reasonable to apply an interest rate equal to the Bank of Canada's Bank Rate plus one and one-half per cent to loss factor charges that are recalculated for the historical period. The Review Panel determined that Milner Power did not identify findings in Decision 790-D04-2016 that are contrary to the Hearing Panel's finding that no party had stated that it intended to use compound interest or included a frequency for doing so.

The Review Panel found that Milner Power had not demonstrated that the Hearing Panel made an error of fact in its findings regarding the submissions received concerning compound interest. Further, Milner Power did not persuade the Review Panel that such an error, if it was made, could lead the AUC to materially vary the decision.

*Financial Harm*

Milner Power submitted that the Hearing Panel failed in the Decision to consider that some generators of the same ISO rate class suffered financial harm and that others benefited by being overpaid, and that the AUC has no choice but to use compound interest to address this financial harm.

The 790 Panel made no findings to the effect that the award of interest, in any configuration, was intended to provide full restitution. Rather it acknowledged that the award of interest would not do this. Interest was found to be awarded to help rectify the time value of money issue, not to provide full restitution. The Review Panel found that it was clear on the face of Decision 790-D04-2016 that the 790 Panel, in considering awarding any interest, had considered if awarding interest was necessary to consider the time value of money and further, it is clear that the 790 Panel was aware of the legislative requirements under the *Electric Utilities Act*.

As compound and simple interest both account for the time value of money, and as there is no finding by the 790 Panel that interest is intended to provide full restitution, the Review Panel found that Milner Power failed to demonstrate that the hearing panel erred in law by finding that simple interest should be awarded.

*Effect of AUC Ruling in Proceeding 790 to Prohibit Reviews*

Beyond review of the type of interest awarded, Milner Power proposed that the AUC, on its own initiative, conduct a review on the rate of interest in Decision 790-D04-2016. Milner Power argued that the AUC should award an appropriate rate and type of interest. Because the 790 Panel precluded reviews from parties, an AUC initiated review would be the only remedy available to Milner Power or any other party.

The AUC denied Milner Power's request. As set out above the Review Panel was not persuaded that the Hearing Panel had made an error of law when determining that the 790 Panel had not considered that interest was intended to provide full restitution. Further, the level of interest was a matter that had been addressed by the 790 Panel and had further been upheld on appeal. The 790 Panel's rulings did not prevent Milner Power or any other party from seeking relief from the court. The scope of the Decision was restricted to the type of interest, simple or compound. Requesting that the AUC initiate a review on the kind of interest through a review request in this proceeding would undermine the certainty and finality on this issue following the decision of the Alberta Court of Appeal.

*Default Position*

Milner Power argued that the Hearing Panel erred in law by adopting, as a default position, that interest should be simple. The Review Panel found that the Hearing Panel had accurately considered applicable precedents, including the cases noted by Milner Power. The Review Panel was not convinced that Milner Power had demonstrated either on the face of the Decision or on a balance of probabilities that the Hearing Panel made an error of law on this ground.

In answering the preliminary question, the Review Panel found that Milner Power Inc. did not meet the requirements for a review of Decision 26084-D01-2021.

***Process to Establish 2023 Rates for Alberta Electric and Gas Distribution Utilities, AUC Decision 26354-D01-2021***

***DFO - Cost-of-Service Applications***

In this decision, the AUC set out how it will process the 2023 cost-of-service ("COS") applications that will be filed by the electric and gas distribution facility owners ("DFOs"). The AUC has prescribed the minimum level of detail each application is expected to include to support the DFOs' 2023 revenue requirement forecasts. The AUC will adopt a hybrid methodology for assessing the 2023 forecasts where the extent to which expenditures are examined is guided by the nature, size or complexity of the associated cost to facilitate a streamlined review of the upcoming 2023 COS applications. The AUC also prescribed filing dates for these applications.

Background

Rates for the electric and natural gas DFOs under the AUC's jurisdiction are currently set according to the performance-based regulation ("PBR") plans established in Decision 20414-D01-2016 (Errata). These plans are effective from January 1, 2018, to December 31, 2022, and apply to the four electric DFOs: ATCO Electric Ltd., FortisAlberta Inc., ENMAX Power Corporation, and EPCOR Distribution & Transmission Inc.; and the two natural gas DFOs: ATCO Gas and Pipelines Ltd., and Apex Utilities Inc. (formerly AltaGas Utilities Inc.).

The AUC commenced this proceeding to determine alternatives for streamlining the traditional line-by-line review of DFOs' forecast costs while meeting the objectives set out in Bulletin 2021-04. The objectives are identifying efficiencies achieved by the DFOs during the 2018-2022 PBR term and passing the benefits on to customers, realigning the DFOs' costs and revenues and examining the DFOs' forecast costs and rates to ensure they are reflective of the economic situation in Alberta; and assessing actual DFO costs in the 2018-2022 PBR term for the purposes of approving 2023 opening rate base and ensuring forecasts are justified based on the prior-period actuals. The AUC further stated that the rates approved for 2023 under this COS review might be used as going-in rates for any subsequent PBR term.

Form of Streamlined Review

The AUC will adopt a hybrid methodology under which the review of expenditures is guided by the nature, size, or complexity of the associated cost, allowing the AUC to focus on certain cost categories while other costs could be assessed in a more streamlined manner. The AUC agreed that each DFO should be allowed to develop its 2023 forecast on its own accord with an understanding that the utility bears the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement. The AUC found that adopting a hybrid methodology permits DFOs to both streamline their submissions pertaining to costs that are routine or less controversial and to tailor and focus their 2023 COS applications on complex issues. The AUC further considered that a hybrid methodology achieves an appropriate balance between regulatory efficiency and providing an adequate opportunity for interveners and the AUC to test a DFO's case.

Level of Detail for the 2023 COS Applications

The AUC prescribed a particular form of presenting 2023 forecasts by way of an AUC-developed template. The DFOs were directed, at a minimum, to fill out the template as part of their 2023 COS application filings but may supplement their application and/or template with additional information and schedules as they deem necessary.

*Operating and Maintenance Costs*

The AUC prepared and requested parties to provide feedback on a draft schedule for operation and maintenance ("O&M") expenses. The schedule was developed using descriptions provided in prior Rule 005 filings from electric DFOs, where the majority of DFOs presented information at a Uniform System of Accounts ("USA") level.

The AUC found that there is merit in assessing the three-year average (2018-2020) of actual O&M costs against the 2023 forecast and directed the DFOs to include comparisons, explanations of any significant changes, actions taken to manage O&M expenditures, a description of new actions to manage O&M costs as well as an explanation of the effect of trends in the Alberta economy in their 2023 COS applications.

*Capital Costs*

To reflect the actual performance of the DFOs in the last two years of the present PBR plans, the AUC accepted the DFOs' request for placeholder treatment for the opening 2023 rate base. This will not preclude the AUC from examining any variances between the actual opening 2023 rate base and the placeholder amount in a future proceeding, which could result in 2023 disallowances.

The AUC found that allowing deferral accounts or true-ups for capital programs that are driven by external factors will result in additional subsequent applications, which contradicts the AUC's objective of an efficient regulatory process. The AUC is confident that the DFOs have the knowledge and experience to anticipate, plan for, and provide a one year 2023 forecast for externally driven capital programs and will therefore not approve deferral account treatment for these programs.

To assist the AUC in achieving its objectives for rebasing while allowing for an efficient regulatory process, the DFOs were directed to provide similar level information in respect of O&M costs and capital costs.

The AUC gave parties until September 1, 2021, to develop the proposed uniform approach to reporting capital-related items to be used in the rebasing schedules for reporting purposes in the 2023 COS review applications.

*Materiality Threshold*

The AUC adopted materiality thresholds for testing the 2023 forecast O&M and capital costs and directed the DFOs to apply them in the 2023 COS applications.

*Identification and Quantification of Efficiencies*

One of the guiding PBR principles used by the AUC is that customers and the regulated companies should share the benefits of a PBR plan. The AUC considered that this principle remains an important consideration when establishing 2023 rates through a COS review.

The AUC expects that DFOs tracked and monitored their expenditures in various accounts, or cost centers, as a normal course of managing their businesses. In the AUC's view, where costs have changed or trended in a certain direction, DFOs should be in a position to explain what has caused the changes, be it an internal cost-reducing action or the result of external factors. Further, DFOs should be able to quantify the outcomes of the initiatives they undertook.

If a DFO is not able to satisfactorily demonstrate to the AUC how cost reductions will be flowed through to its customers in its forecast 2023 revenue requirement, the AUC may consider a more mechanistic, high-level approach to ensure ratepayers benefit from the efficiencies achieved during the PBR term.

*Prudence Review*

The DFOs expressed concern with reference to an “assessment of prudence” in the Bulletin and stated that a prudence review should not occur because actual costs incurred under the incentives of PBR are presumed to be prudent.

One of the fundamental differences between the present PBR plan and the 2013-2017 PBR plan is the absence of the capital tracker funding mechanism in its legacy form. The capital tracker funding mechanism in the 2013-2017 PBR plan applied to the majority of the DFO’s capital-related costs and resembled a traditional COS review process. When this mechanism was replaced with an “envelope” funding type of approach in the current PBR plan through the K-bar factor, DFOs were provided with the majority of capital funding on the basis of a pre-determined formula; this capital was not subject to the same level of AUC scrutiny that was applied to the capital tracker program.

The AUC maintained its view that actual costs incurred under the incentives of PBR should generally be deemed prudent and not be subjected to the same level of assessment as expenditures under COS regulation. However, given that all capital expenditures were managed under the K-bar funding envelope with no AUC scrutiny under the 2018-2022 PBR plan, the AUC may require the DFOs to demonstrate the reasonableness of the costs of certain programs.

*Other Matters*

*Pre-filing of Historical Data -* The AUC considers that the timely completion of the COS proceedings in the compressed timeframe available will be aided through the pre-filing of historical DFO data for 2013 to 2020. Accordingly, the AUC directed each DFO to file on the record of its respective proceeding such historical data, using the rebasing template format reflective of the developed capital groupings, at least one month prior to the deadline date for 2023 COS application filings.

*Depreciation Studies and Technical Updates -* In the AUC’s view, consideration of depreciation and other similar COS studies in conjunction with a review of 2023 COS applications will hinder the AUC’s objective of promoting regulatory efficiency and achieving a streamlined rebasing process. As such, depreciation applications, or technical updates, will be considered outside the forthcoming 2023 COS applications. However, to ensure that a DFO’s 2023 rates are reflective of the most up to date information and to minimize future true-ups, the AUC was prepared to approve the updated depreciation costs on a placeholder basis in COS review proceedings for those DFOs that wish to update their depreciation parameters. These placeholders may be adjusted as a result of the AUC’s review of the 2023 COS applications. Each DFO will be given an opportunity to file its depreciation application following the completion of the COS review process, at which point the depreciation parameters approved as part of the DFO’s 2023 forecast will be trued up to reflect any disallowances in the AUC’s decision.

*Billing Determinant Forecast -* The 2023 billing determinant forecast should be developed using AUC-approved methodologies for each DFO unless there is a valid reason for departure, in which case, a detailed explanation for such departure should be provided. The 2023 billing determinant forecast should reflect the rate class allocation last approved in each DFO’s respective Phase II proceeding. Each utility was directed to provide an analytical and numerical explanation of how the Alberta economy and COVID-19 pandemic factors were considered in arriving at the proposed 2023 billing determinant forecast.

*Investment Level Changes -*The AUC found that to facilitate an efficient regulatory process and to minimize the regulatory burden associated with undertaking a review of six COS applications, it would not allow changes to investment levels to be included in the 2023 COS applications.

*Deferral Accounts -* The AUC confirmed that currently approved deferral accounts and rate riders would remain applicable in the 2023 COS year, as clarified in this decision. The differences between forecast and actual costs for items in these accounts will be subsequently trued up. In this respect, placeholder treatment will also be afforded to those 2021 and 2022 costs requiring alignment to establish the 2023 opening rate base.

*Timing* - The AUC will assess the 2023 COS applications in pairs in a staggered manner in accordance with the schedule set out in the decision.

***TransAlta Corporation 2019-2021 Transmission General Tariff Application and 2018 Edmonton Region Project Direct Assigned Capital Deferral Account Compliance Filing, AUC Decision 26436-D01-2021***
***Electricity - Rates***

In this decision, the AUC approved, in part, the 2019-2021 general tariff application ("GTA") from TransAlta Corporation ("TransAlta"), as Manager of the TransAlta Generation Partnership, and the application for approval of its compliance filing to Decision 25369-D01-2020 regarding the Edmonton Region 240 kilovolt Upgrades Project.

<u>2019-2021 GTA</u>

As part of its GTA, TransAlta submitted that its transmission revenues for 2019, 2020, and forecast for 2021 were approximately $ 7.6 million, $8.4 million and $7.6 million, respectively. It further submitted that its total transmission costs for the same years were $7.6 million, $8.4 million and $8.2 million, respectively.

The AUC determined that not all costs for which TransAlta sought recovery had been reasonable. The following discusses only the contentious issues of the GTA.

*TransAlta' 2021 Escalation Rate for Non-Union Salary, Contractor, and General Inflation*

The AUC determined that the escalation rate of 1.75 percent non-union salary, contractor, and general inflation for 2021, requested by TransAlta, was not reasonable.

Given that TransAlta did not undertake any studies to assess the reasonableness of the applied-for 2021 escalator and the impacts of the COVID-19 pandemic on the Alberta economy, the AUC found the requested escalator to be unreasonably high and approved a 0.8 percent escalation rate.

*TransAlta's Payments in Lieu of Property Tax to Certain First Nations*

Issues arose regarding the reasonableness of TransAlta's payments in lieu of property tax to four First Nations that do not have a property tax bylaw. TransAlta has transmission facility owner ("TFO") assets on the lands of multiple First Nations. Four of these First Nations do not have a property tax bylaw. TransAlta makes "payments in lieu of taxes" pursuant to bylaw agreements, which utilize the mill rates of surrounding communities to determine the amount of the payments. The amounts paid by TransAlta are based on the Alberta Municipal Affairs linear property assessment and the mill rates of neighboring or adjacent counties.

The AUC had assessed and approved this methodology in previous TransAlta GTAs. The AUC remained of the view that it is a reasonable method.

*Is it Reasonable for TransAlta to Continue to Adopt AltaLink Management Ltd.'s Depreciation Practices?*

The AUC questioned the reasonableness of TransAlta continuing to adopt AltaLink Management Ltd. ("AML")'s depreciation practices, including their approved depreciation parameters and depreciation rates and AML's capitalize and expense salvage methodology.

In the past, the AUC has approved TransAlta's approach to adopting AML's depreciation practices as it considered this to be more efficient than requiring TransAlta to maintain actuarial data to conduct its own depreciation-related studies. The AUC noted that there are minor differences between AML's and TransAlta's implementation of the capitalize and expense method. However, the AUC accepted the explanation from TransAlta that suggested that the difference cannot be avoided and does not cause an unreasonable divergence from the form and intent of the capitalize and expense method. The AUC determined that it remains an efficient method for TransAlta to continue to adopt AML's depreciation practices.

*Should TransAlta Correct its Applied-for Cost-of-Debt Rates to Match AML's Approved Rates for 2019-2021?*

Similar to its previous GTAs, TransAlta requested to use the cost-of-debt rates that were approved for AML. TransAlta applied for a debt rate of 4.00 percent for each of 2019, 2020, and 2021. It indicated that it had obtained these rates from AML's cost-of-debt rates for the 2019-2021 test period. The AUC noted that AML's approved cost-of-debt rates for the 2019-2021 test period differed from the rates TransAlta applied for in this application. TransAlta was directed to update its cost-of-debt rates to match AML's approved rates as follows: 3.93 percent for 2019, 3.97 percent for 2020 and 3.98 percent for 2021.

*Should the AUC Approve TransAlta's Applied-for Capital Addition Amounts Related to Rate Base Projects?*

TransAlta requested approval of actual aggregate capital addition amounts related to transmission capital maintenance projects of $6.609 million for 2019 and $2.078 million for 2020, as well as forecast capital additions totaling $3.397 million for 2021.

The AUC did not approve capital addition amounts of approximately $466,000 for 2019 and $804,000 for 2020 related to the Transmission Line Rebuild Project. However, the AUC did approve these amounts as placeholders for 2019 and 2020.

TransAlta filed new information that it had recently identified costs of approximately $700,000 for the line 113L/150L rebuild project that may have been erroneously billed to TransAlta's rate base. TransAlta submitted that the relocation of this amount could require a reduction to TransAlta's revenue and rate base for the 2019-2021 test period and a corresponding increase to AML's revenue and rate base. Accordingly, the AUC decided that TransAlta's proposed 2019-2021 period capital additions of the Transmission Line Rebuild Project will be approved on a placeholder basis.

Regarding the Line 902L Structure 50 Replacement Project, the AUC found that the costs of $4.475 million set out in the application reflect that AML did not have a long lead time to procure materials for and execute this project, and therefore did not anticipate the escalation of costs when it prepared the initial estimates.

The 902L structure 50 replacement was characterized by TransAlta as an urgent repair. The repair was needed to repair the structural failure of a 43-year-old double circuit 240kV steel lattice transmission tower foundation. TransAlta showed that the complexity of the installation and the added material needed led to the increase in costs of the project.

The AUC was satisfied that the drivers of the increase in costs from the initial forecasts had been adequately explained. Accordingly, the AUC was satisfied that in the circumstances that arose for this urgent capital replacement, TransAlta's portion ($4.762 million over the 2019-2021 period) of the cost is reasonable.

<u>AUC Decision</u>

In this decision, the AUC only discussed its findings related to contentious issues. All subjects and requested approvals not discussed in this decision related to the 2019-2021 GTA and the application approval of its compliance filing to Decision 25369-D01-2020 were approved as filed.

## CANADA ENERGY REGULATOR

### *Canadian Natural Resources Limited Application for Access on the Pierson Pipeline and for Just and Reasonable Tolls -* CER Application for Access and Tolls C12225

*Gas - Tolls*

In this decision, the CER denied the application from Canadian Natural Resources Limited ("CNRL") pursuant to section 226 and subsection 239(2) of the *Canadian Energy Regulator Act* ("*CER Act*") requesting an order to receive, transport, and deliver gas on the Pierson pipeline and an order prescribing a just and reasonable toll. The CER did order Nottingham Midstream Limited ("Nottingham") to provide interruptible service for the Pierson pipeline.

Background

The Pierson pipeline is a 10 km natural gas pipeline that delivers gas from Manitoba to the Wolstitmor Gas Gathering system in Saskatchewan. The Pierson pipeline is owned by a subsidiary of Nottingham with no employees and existing only for the purpose of meeting organizational requirements found in the *National Energy Board Act.*

In 2006, CNRL entered into a Gas Purchase Agreement with Nottingham's predecessors for the purchase of gas at the Pierson Battery. In April 2017, Nottingham entered into a verbal agreement with CNRL to modify the 2006 Gas Purchase Agreement for net-zero pricing, which adjusted negative monthly invoices, so the purchase price paid to CNRL was not negative. On 30 April 2020, Nottingham sent a letter to CNRL stating that Nottingham would no longer continue net-zero pricing. Nottingham proposed a return to the terms specified in the 2006 Gas Purchase Agreement. In May 2020, CNRL stopped shipping gas on the Pierson pipeline and began flaring. CNRL and Nottingham had been engaged in negotiations for a new gas purchasing or handling agreement. As one component of the negotiations for an agreement in 2020, Nottingham proposed a capital fee of $2.50/mcf (for volumes up to 25,000 $m^3$/d), $2.00/mcf (for volumes from 25,000 – 40,000 $m^3$/d), and $1.50/mcf (for volumes over 40,000 $m^3$/d).

CNRL argued that Nottingham's proposed capital fees are unjust, unreasonable and unjustly discriminatory against CNRL. CNRL submitted that the fees have no basis in operator expenses of capital investment and do not reflect the cost of providing service on the Pierson pipeline.

Views of the CER

The CER noted that the Pierson pipeline is a small part of a bigger system. To allow the meaningful use of the pipeline, shippers need to have access to the downstream Wolstitmor Gas Gathering System. It noted that without the use of these two sets of facilities, there is no market for gas shipped on the Pierson pipeline. The CER further noted that it does not require tolls in a specific form, only that a company demonstrates that their tolls are just and reasonable and not discriminatory.

*Was CNRL Discriminated Against for Access to and Service on the Pierson Pipeline?*

In determining if CNRL was discriminated against, the CER evaluated whether Nottingham abused its market power. It further considered if the terms of a gas purchase agreement between Nottingham and another party were substantially similar to the terms proposed to CNRL in 2020.

As part of this proceeding, evidence was filed to demonstrate the behavior during and process of negotiations between CNRL and Nottingham. This evidence suggested that CNRL saw flaring its gas as a substitute for shipping its gas on the Pierson pipeline. Further, CNRL waited two months in 2020 to respond to the gas handling agreement proposed by Nottingham. This indicated that Nottingham did not control the pace of negotiations. Therefore, and because CNRL submitted a list of alternatives it saw to obtain value from its gas, the CER determined that Nottingham did not abuse market power.

CNRL submitted that if the gas purchase agreement of Nottingham with Tundra Oil & Gas Ltd. ("Tundra"), executed in March 2021, is more favourable than Nottingham's final offer to CNRL, then Nottingham has discriminated against CNRL. The CER evaluated that gas purchase agreement, which was filed confidentially, and considered it and the comparison to the offer to CNRL in light of the circumstances of the Pierson pipeline. The CER determined that the terms proposed to CNRL were substantially similar to those terms in the Gas Purchase Agreement with Tundra. Accordingly, Nottingham did not discriminate against CNRL when it denied CNRL access to the Pierson pipeline.

*Is Ordering Interruptible Service Appropriate?*

The CER accepted that, at the time of the proceeding, the capacity of the Pierson pipeline was fully contracted. As a result, there was no existing capacity to be offered as a firm service. However, the CER noted that there may be available capacity from time to time. During the proceeding, Nottingham noted its willingness to offer interruptible service, which, by its nature, would not impact Tundra's priority to ship gas on the Pierson pipeline. In accordance with the principle of economic efficiency and no unjust discrimination in service, the CER ordered Nottingham to offer interruptible service.

*What is a Just and Reasonable Toll to be Charged for Interruptible Service?*

Nottingham proposed a gas handling agreement with four principles under which it would offer interruptible service: (i) a capital charge of $2.50/mcf for volumes up to 15,000 $m^3$/d and $1.50/mcf for volumes in excess of this level; (ii) recovery of a volumetric allocated share of operating costs based on actual throughput; (iii) recovery of Nottingham's external costs to participate in this complaint proceeding; and (iv) all solution gas volumes delivered by CNRL must meet the prevailing compression levels of the Pierson pipeline gas stream.

Despite the difference between firm service, as agreed to between Tundra and Nottingham, and interruptible service, requested by CNRL, the CER found that, in this proceeding, tolls for interruptible service would be just and reasonable if they are substantially similar to those from the gas purchase agreement between Tundra and Nottingham.

The CER agreed with Tundra and Nottingham's assertions that the terms of the July 2020 offer to CNRL, as they related to the capital charge beginning at $2.50/mcf, were substantially similar to the terms of the Nottingham - Tundra gas purchase agreement. The CER noted that the fact that CNRL does not have any rights over the capacity of the pipeline or to discounted services in the future simply because it had historically paid tolls on the Pierson pipeline.

The CER found it appropriate to base the recovery of operating costs on actual throughput. This would align with the cost causation principle.

The CER determined that it was not appropriate to include costs to participate in this complaint proceeding in the calculation of tolls to be charged to CNRL. Tolls and tariffs are regulated on a complaint basis. Attempts by CNRL and Nottingham to negotiate were unsuccessful, and CNRL brought forward a complaint. Under complaint-based regulation, this is an appropriate series of events.

The CER was convinced that it is appropriate that all gas volumes delivered by CNRL to the Pierson pipeline must meet the prevailing compression levels of the gas stream. Defining limits of the transported gas is a standard method for the pipeline operator to meet the objective of safe and efficient operation.

<u>Other Matters</u>

This application did not include a request for the extension of facilities. Accordingly, CNRL's term requiring the operating pressure of the Pierson pipeline to be increased is beyond the scope of this proceeding. As sophisticated parties, CNRL and Nottingham are able to negotiate these arrangements within the limits of the *CER Act.*

### *Trans Mountain Pipeline ULC Detailed Route Hearing MH-010-2020 – Chilliwack School District, District Parent Advisory Council, and City of Chilliwack*

***Pipelines - Detailed 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-kilometer-long Trans Mountain Pipeline ("TMPL") system in Alberta and British Columbia with approximately 981 kilometers 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 kilometers of the existing pipeline between Edmonton and Burnaby. Trans Mountain requested approval of a 150-meter-wide corridor for the TMEP pipeline's general route.

The TMEP was approved by Order in Council ("OIC") P.C. 2016-1069 in November 2016. The NEB issued Certificate OC-064 and began work on various regulatory processes, including the 2017/18 detailed route approval process. Certificate OC-064 included approval of a corridor through Chilliwack that followed BC Hydro transmission lines for some distance ("Original Corridor"). There was later approval of a realignment (the "Chilliwack Realignment") to vary the pipeline corridor for a short section, relocating the TMEP away from the BC Hydro lines and to within the existing TMPL right-of-way ("RoW"). The realignment was outside the Original Corridor for approximately 1.8 kilometers.

Following an appeal, a second public hearing process, an NEB Reconsideration Report, and a further approval of the TMEP by an OIC, the NEB issued Certificate OC-065 (the hearings which were held which led to Certificate OC-064 and OC-065 are referred to herein as "Certificate Hearings"). 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 considered approval of the PPBoR under the provisions of the *CER Act*.

Detailed Route Hearing MH-010-2020

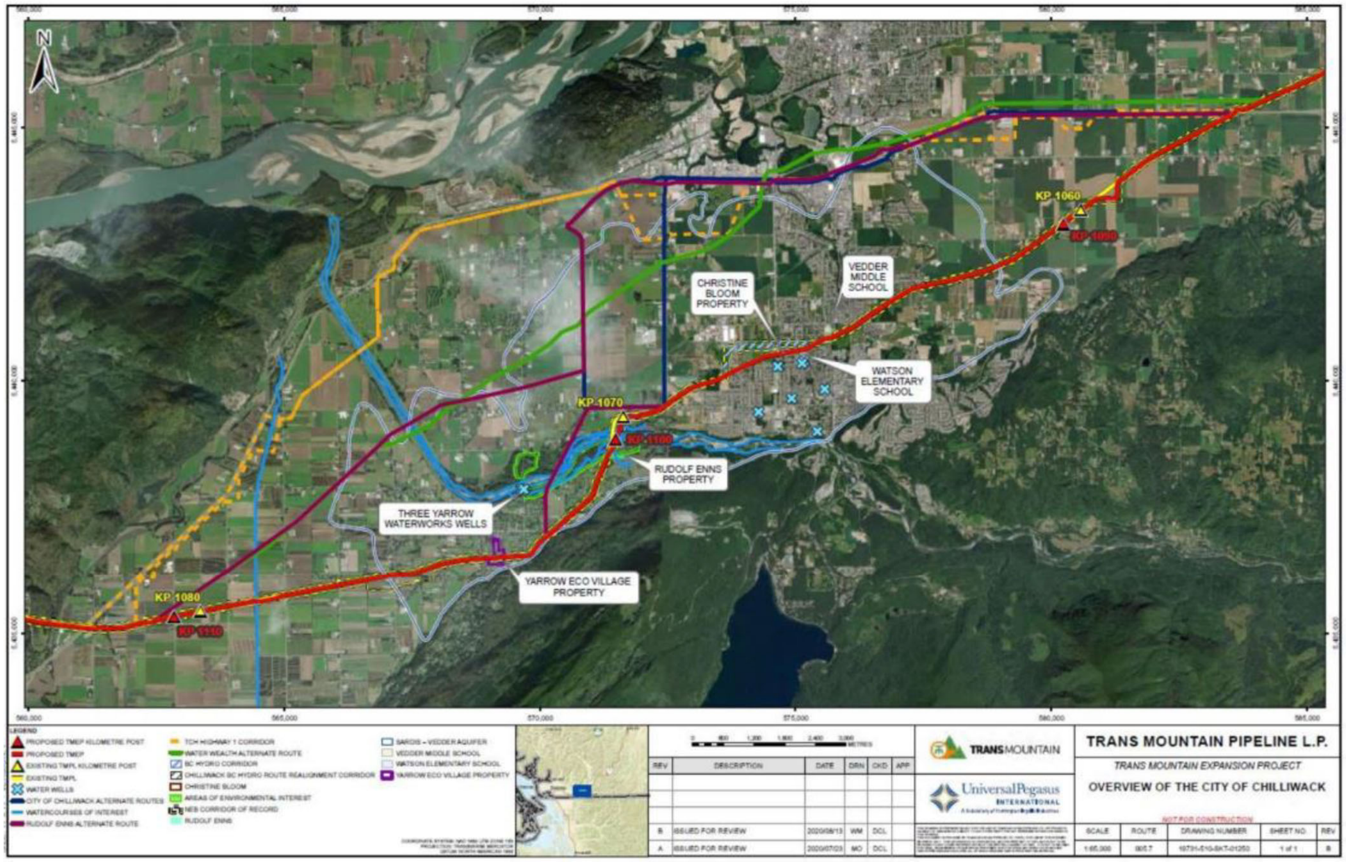
On 13 and 16 September 2019, Chilliwack filed SOOs seeking to resume its 2017/2018 detailed route hearing (MH-020-2018). On 23 September 2019, the CER received an SOO from the S'ólh Téméxw Stewardship Alliance ("STSA") opposing the proposed detailed route and the methods and timing of construction throughout various segments of the TMEP, which was later withdrawn.

This detailed route hearing's geographical focus overlapped with that of Detailed Route Hearings MH-026-2020, MH-013-2020, MH-015-2020, and MH-026-2020. These hearings and MH-010-2020 were collectively referred to as the "Chilliwack Hearings". However, each hearing considered its own evidentiary record and unique issues and applied to specific tracts of land. Tract 2307 in Segment 6.3 was the section at issue in this proceeding (the "Lands").

Overview of the Proposed Route on the Lands

The following figure depicts Trans Mountain's proposed detailed route Chilliwack's alternate routes, the District Parent Advisory Council's ("DPAC's") preferred route, and Watson Elementary School:

**Figure 3 - Trans Mountain's proposed route, Chilliwack's alternate routes, DPAC's preferred route, and Watson Elementary School (C07675-2)**




Is Trans Mountain's Proposed Route the Best Possible Detailed Route?

(a) Has Trans Mountain adequately addressed concerns with the proximity of the proposed route to Watson Elementary School?

Trans Mountain's proposed route crosses Watson Elementary School. In determining whether Trans Mountain adequately addressed concerns with the proximity of the proposed route to Watson Elementary School, the CER considered submissions from Chilliwack School District #331 (the "School District"), DPAC, and Trans Mountain.

The CER determined that Trans Mountain had adequately engaged with the School District. The CER emphasized that Trans Mountain, in response to engagements with school representatives, created the School Guidelines to supplement school emergency planning and that Trans Mountain has committed to providing it every two years and to make it publicly available. Further, the CER noted Trans Mountain's commitment to regularly meet with school representatives to review emergency protocols, pipeline safety and to keep them informed. The CER agreed that the safety of school children and others is the primary concern. It determined that Trans Mountain's proposed mitigation, including scheduling construction activities on certain lands between the months of July and August to avoid impacts on schools, restricting access to the construction zone by fencing the entire construction area, and more, addresses potential safety concerns associated with the proposed route through the Watson Elementary School property.

In Detailed Route Hearing MH-026-2020, the WaterWealth Project ("WaterWealth") proposed an alternate route. DPAC supported this alternative. This proposed alternative did not intersect with schools, residential areas, wells, significant salmon habitat enhancement areas and has half as many private wells within the 150-meter inventory distance required by project conditions. The CER found that this proposed alternate route would result in land fragmentation which is inconsistent with the approved routing criteria. The CER concluded that adding a second RoW would increase overall impacts. Further, the CER found that DPAC's preferred route would involve construction and engineering challenges that are insurmountable.

With regard to the Sardis-Vedder Aquifer, the CER noted that the Chilliwack Realignment hearing considered in detail the risk that the Approved Corridor (and thus of Trans Mountain's proposed route) posed to the Aquifer and Chilliwack's water wells. The Realignment Report concluded that the risk to Chilliwack's wells is minimal, but not zero. The CER agreed. It rejected the suggestion that Trans Mountain install a trench liner, finding that it would likely introduce pipeline integrity challenges and that the TMEP leak detection system made a trench liner unnecessary.

The CER found that Trans Mountain's flexible application of its routing criteria was appropriate in this case. It found that Trans Mountain had the onus of proving on a balance of probabilities that its proposed route is the best possible detailed route and that its proposed methods and timing of construction are the most appropriate. The CER examined alternate routes and found that they were inferior to Trans Mountain's proposed route. It found that Trans Mountain's proposed route is the best possible detailed route.

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

Issues arose regarding Trans Mountain's proposal to construct the TMEP with a conventional open-trench construction methodology. SOO filers submitted that this would create unnecessary risk to students, staff and parents.

Trans Mountain had already, as part of the Chilliwack Realignment hearing, proposed mitigation measures, including scheduling construction activities between the months of July and August and restricting access to the construction zone by using fencing around the entire construction area. It would further implement traffic management plans and measures relating to project vehicles and equipment. Further, in the case that the construction could not be completed in July/August, Trans Mountain committed to further secure and monitor the construction site to ensure that it cannot be accessed by students.

The CER was satisfied that the proposed construction method is the most appropriate and noted its expectation of Trans Mountain to implement the measures and mitigation established through the Certificate Hearings and this detailed route hearing to address potential impacts during construction.

<u>Is Trans Mountain's Proposed Timing of Constructing the Pipeline the Most Appropriate?</u>

Trans Mountain proposed to construct the pipeline between July and August 2021 and to have the trench backfilled prior to school returning in September 2021.

The CER noted that Trans Mountain's commitments are significant and may further reduce potential impacts. It emphasized its expectation that Trans Mountain stands by these commitments before, during, and after construction. The CER noted DPAC's concern that starting and deferring construction until summer 2022 would result in an inactive construction site for an extended period of time, posing an inconvenience on Watson Elementary School and its students for the entire school year. Trans Mountain is expected to continue its engagement with the School District prior to construction in order to discuss specific concerns and potential alternative mitigation measures for this contingency scenario.

<u>Conclusion</u>

The CER decided that Trans Mountain's proposed route is the best possible detailed route on the Lands, and the proposed methods and timing of constructing the pipeline are the most appropriate, subject to the commitments made by Trans Mountain and ongoing compliance with the Certificate OC-065 conditions.

***Trans Mountain Pipeline ULC Detailed Route Hearing MH-011-2020 – Christine Bloom and City of Chilliwack***
***Pipelines - Detailed Route Hearings***

Background

The background of this proceeding is set out in this newsletter in *Trans Mountain Pipeline ULC Detailed Route Hearing MH-010-2020 – Chilliwack School District, District Parent Advisory Council, and City of Chilliwack.*

Detailed Route Hearing MH-011-2020

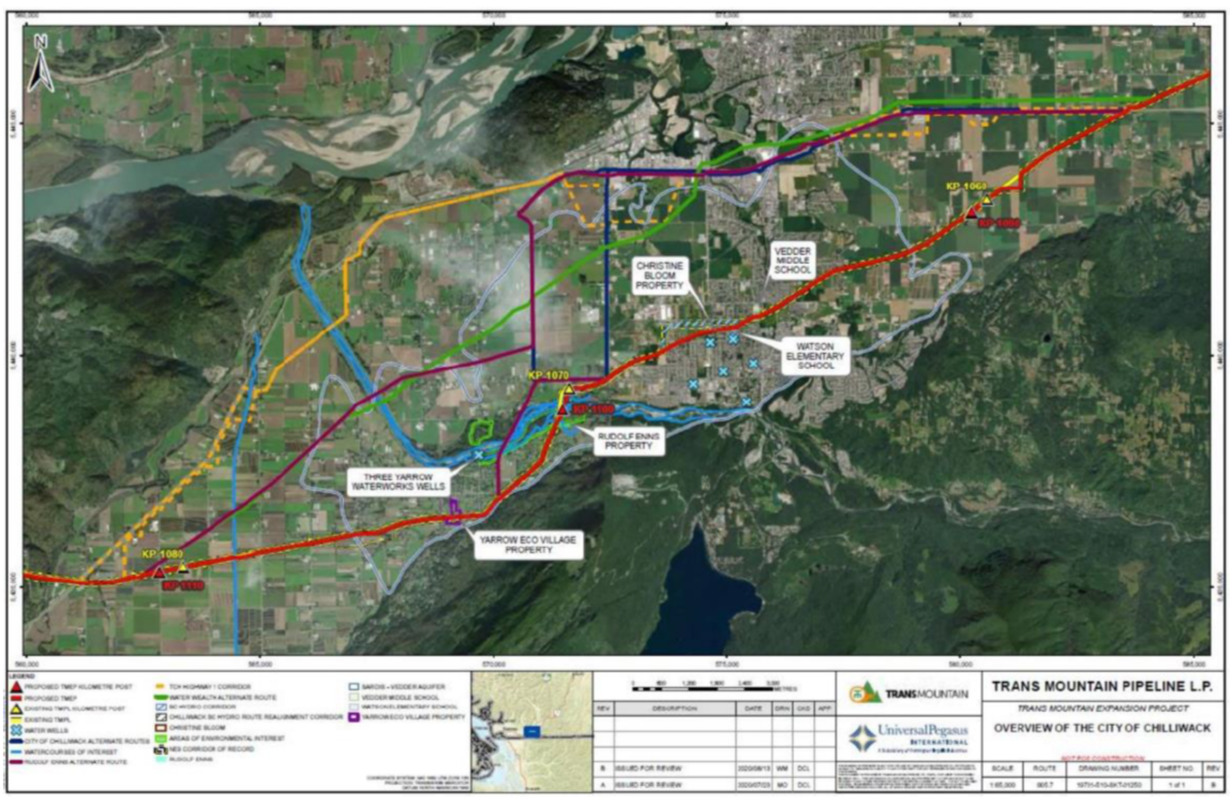
In September 2019, Ms. Christine Bloom filed SOOs opposing the proposed detailed route and methods and timing of construction on the lands at issue in this detailed route hearing (the "Lands"). The City of Chilliwack ("Chilliwack") filed SOOs seeking to resume its 2017/2018 detailed route hearing. The WaterWealth Project ("WaterWealth") participated as an intervener. An SOO from an Indigenous group was submitted and withdrawn.

On 31 January 2020, the CER issued a Procedural Direction explaining that there are a number of instances where the geographical focus of one detailed route hearing overlaps with that of one or more other hearings. This Detailed Route Hearing MH-011-2020 related to Tract 2352 only, which is in Segment 6.3 (the "Lands"). All other tracts of land in Segments 6.2, 6.3, and 6.4 were the subject of other detailed route hearings. These five hearings are referred to collectively as the "Chilliwack-Area Hearings."

Overview of the Proposed Route on the Lands

The following figure depicts Trans Mountain's proposed detailed route (in red), as well as alternate routes proposed by WaterWealth (supported by Ms. Bloom) (in green) and Chilliwack (in dark blue):

**Figure 3 – Trans Mountain's proposed route, Chilliwack's alternate routes, WaterWealth's alternate route, and Ms. Bloom's property (C07675)**



Is Trans Mountain's Proposed Detailed Route for the TMEP Pipeline the Best Possible Detailed Route?

The CER noted that Trans Mountain's proposed route is parallel to and within the existing TMPL RoW for the entire route crossing the Lands. The proposed TMEP will be placed further away from Ms. Bloom's home than where the existing TMPL is presently located.

The CER was of the view that Ms. Bloom's concerns about disruptions to Chilliwack residents, and emergency response in the event of a spill, are general in nature and not specific to the Lands and were therefore not within the scope of this hearing. These general matters were considered in the earlier Certificate Hearings. While the CER agreed that human health, in general, is beyond the scope of this detailed route hearing, it found that Ms. Bloom's particular health concerns were within scope. However, Ms. Bloom did not provide an explanation of how the proposed route, or a leak or spill, may aggravate her health conditions or impact her, above and beyond the potential impacts on human health that were considered and addressed in the Certificate Hearings.

With regard to the Sardis-Vedder Aquifer, the CER noted that the Chilliwack Realignment hearing considered in detail the risk that the Approved Corridor (and thus of Trans Mountain's proposed route) posed to the Aquifer and Chilliwack's water wells. Relatively little new evidence was submitted in this Detailed Route Hearing MH-011-2020 concerning that risk. The Realignment Report concluded that the risk to Chilliwack's wells is minimal, but not zero. The CER agreed. It rejected the suggestion that Trans Mountain install a trench liner, finding that it would likely introduce pipeline integrity challenges and that the TMEP leak detection system made a trench liner unnecessary.

The CER found that Trans Mountain applied its routing criteria appropriately. It found that Trans Mountain had the onus of proving on a balance of probabilities that its proposed route is the best possible detailed route and that its proposed methods and timing of construction are the most appropriate. The CER examined alternate routes and found that they were inferior to Trans Mountain's proposed route. It found that Trans Mountain's proposed route is the best possible detailed route.

Are Trans Mountain's Proposed Methods of Constructing the Pipeline the Most Appropriate?

The CER noted that Trans Mountain proposed to construct the TMEP within the existing TMPL RoW for the entirety of the route crossing on the Lands, using a conventional open-trench construction methodology. The CER found that, on a balance of probabilities, Trans Mountain's proposed methods of constructing the pipeline on the Lands are most appropriate in the circumstances.

The CER accepted that Trans Mountain's commitment to using a Heavily Restricted Footprint on the Lands appropriately minimized the impacts. A Heavily Restricted Footprint, where construction is completed with a shored trench or stove pipe technique, uses a small and vertically cut trench. As described by Trans Mountain, the pipeline is constructed within the trench, and all welding and coating activities take place within the shored excavation. This technique allows for minimal use of temporary workspace to the greatest extent possible. The only space affected is required for the width of the shored trench, for lowering equipment to place the pipe within the trench, and for access. Typically, the excavated material is trucked out and back into the temporary workspace instead of being stored on site. In making its finding, the CER placed significant weight on these mitigation measures.

Is Trans Mountain's Proposed Timing of Constructing the TMEP Pipeline the Most Appropriate?

The CER noted that Trans Mountain intends to commence construction activities on the Lands in Q3 of 2021, subject to regulatory approval. It further noted that Trans Mountain is making efforts to expedite the construction schedule in the area to minimize impacts on residents and has committed to keeping Ms. Bloom apprised of Trans Mountain's construction plans. Ms. Bloom did not make submissions on this issue and Chilliwack's concerns related to issues outside of the Lands. The CER was of the view that Trans Mountain's proposed timing of constructing the pipeline across the Lands is the most appropriate.

Conclusion

The CER decided that Trans Mountain's proposed route is the best possible detailed route on the Lands, and the proposed methods and timing of constructing the pipeline are the most appropriate, subject to the commitments made by Trans Mountain and ongoing compliance with the Certificate OC-065 conditions.

## ***Trans Mountain Pipeline ULC Detailed Route Hearing MH-013-2020 – Rudolf and Debra Enns and City of Chilliwack***

***Pipelines - Detailed Route Hearings***

Background

The background of this proceeding is set out in this newsletter in *Trans Mountain Pipeline ULC Detailed Route Hearing MH-010-2020 – Chilliwack School District, District Parent Advisory Council, and City of Chilliwack*.

Detailed Route Hearing MH-013-2020

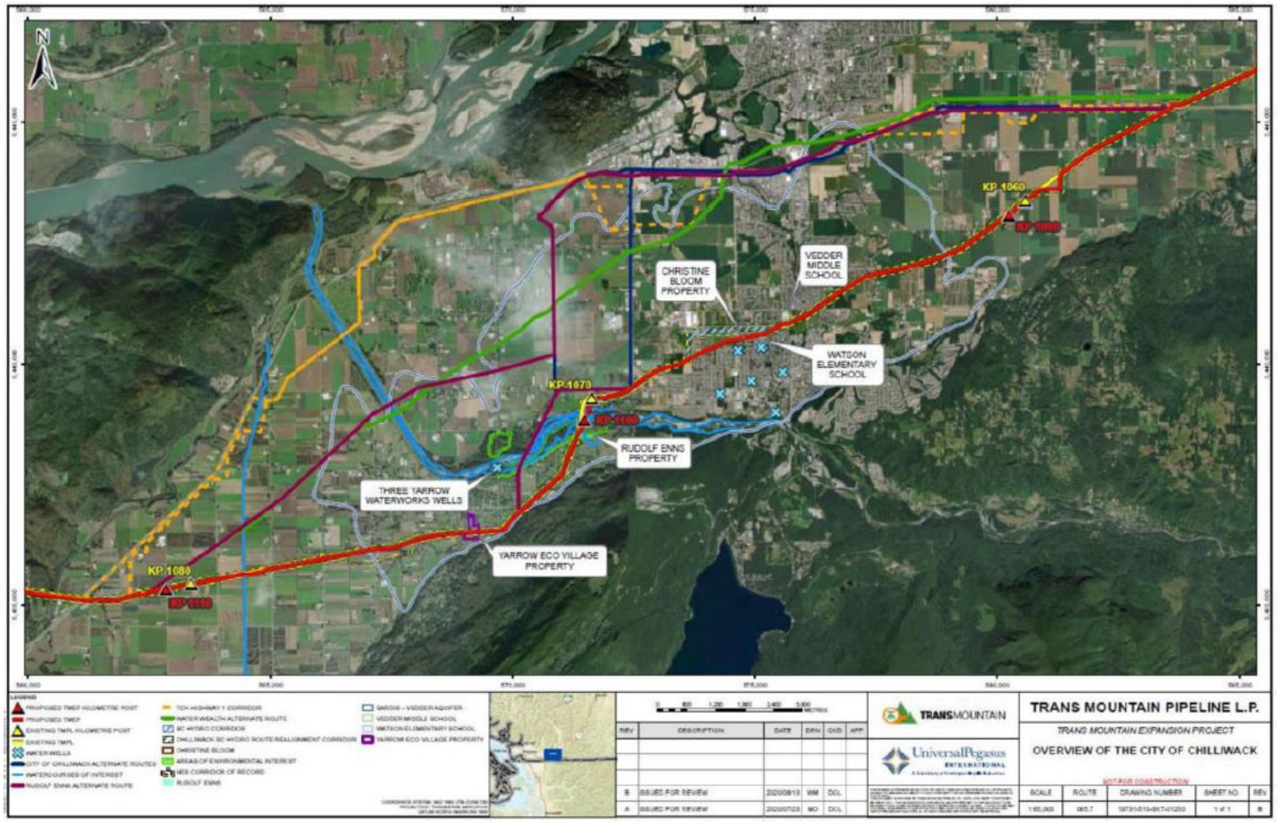
In September 2019, Mr. and Mrs. Enns filed a statement of opposition ("SOO") seeking to resume their 2017/2018 detailed route hearing, and Chilliwack filed SOOs seeking to resume its 2017/2018 detailed route hearing. An SOO from an Indigenous group was submitted and withdrawn.

On 31 January 2020, the CER issued a Procedural Direction explaining that there are a number of instances where the geographical focus of one detailed route hearing overlaps with that of one or more other hearings. This Detailed Route Hearing MH-013-2020 relates to Tract 2410 only, which is in Segment 6.4 (the "Lands"). All other tracts of land in Segments 6.2, 6.3, and 6.4 are the subject of other detailed route hearings. These five hearings are referred to collectively as the "Chilliwack-Area Hearings."

Overview of the Proposed Route on the Lands

Rudolf and Debra Enns are the registered owners of the Lands. The figure below shows Trans Mountain's proposed route (in red), Chilliwack's alternative routes (in dark blue), Mr. and Mrs. Enns' alternate routes (in purple), and other features in the area of the Lands. Mr. and Mrs. Enns proposed two alternate routes in the Chilliwack area, which are described as follows: (i) a route overlapping with alternate routes proposed in other detailed route hearings (Chilliwack/WaterWealth Alignment); and (ii) a shorter route proposing a new crossing of certain environmental features (Keith Wilson Road Alignment).

**Figure 3 – Trans Mountain's proposed route, Mr. and Mrs. Enns' alternate routes, and Chilliwack's alternate routes (Source: C08908)**




Is Trans Mountain's Proposed Route the Best Possible Detailed Route?

The CER acknowledged Mr. and Mrs. Enns' concern about the implications of a shallow water table on the Lands where the Trans Mountain Expansion Project ("TMEP") and a new valve would be located. The CER noted that Trans Mountain selected the proposed TMEP valve for the site conditions, as required in CSA Z662 Clause 4.4.9. The CER was of the view that, with the valve design and proposed construction methods and mitigation, Trans Mountain has taken sufficient measures to address the implications of a shallow water table. Further, the CER was satisfied that Trans Mountain's Groundwater Management Plan provides appropriate measures to mitigate construction through areas with shallow groundwater.

The CER acknowledged that the potential for a spill on the Lands exists, although it found it unlikely. In the event a spill does occur on the Lands, there could be impacts on the adjacent Browne Creek Wetlands. The CER noted that the potential effects of spills or leaks were extensively examined during the Certificate Hearings and resulted in numerous commitments and conditions related to pipeline integrity, leak detection, and spill response. Of particular note, Trans Mountain's pipeline environmental protection plan ("EPP") contains mitigation measures to prevent deleterious substances from entering wetlands during construction.

The proposed route does not cross the Yarrow Waterworks wells, which are located approximately one kilometer from the route. Nevertheless, the CER accepted that spills or leaks from a pipeline can have broad impacts downstream or downgradient. The potential effects of spills or leaks were extensively examined during the Certificate Hearings, which resulted in numerous commitments and conditions regarding pipeline integrity, leak detection, and spill response.

The CER was of the view that Trans Mountain appropriately applied its routing criteria in a flexible manner in this case. Trans Mountain's Original Corridor applied the second general criterion (routing alongside an existing RoW), as Trans Mountain was attempting to avoid the site-specific densely populated area associated with the first general criterion (routing alongside the existing TMPL). However, when even more substantial site-specific engineering challenges with the Original Corridor came to light, circumstances changed, and Trans Mountain considered that the next-best option was to apply the first criterion.

The CER noted that Trans Mountain had the onus to prove, on a balance of probabilities, that its proposed route is the best possible detailed route and that its proposed methods and timing of construction are the most appropriate. The CER was of the view that Trans Mountain undertook sufficient technical analyses with respect to Mr. and Mrs. Enns' alternate routes to meet this burden.

The CER concluded that Mr. and Mrs. Enns's alternate routes were not viable alternates because one of the suggested alignments was not technically feasible, and another suggested alignment was inferior due to the environmental impacts at the Vedder River crossing. While Mr. and Mrs. Enns' alternate routes no longer intersected the Lands, thereby avoiding the potential impacts on the Browne Creek Wetlands from a spill on the Lands, the CER was of the view that the mitigation measures proposed by Trans Mountain would appropriately minimize both the potential for a spill to occur and the potential effects to the wetlands in the event of a spill on the Lands. This advantage of Mr. and Mrs. Enns's alternate routes was therefore outweighed in these circumstances.

Are Trans Mountain's Proposed Methods of Constructing the Pipeline the Most Appropriate?

The CER noted that Trans Mountain proposes to construct the TMEP on the Lands using a conventional open-trench construction methodology. It proposes crossing the Vedder River by way of a Direct Pipe installation with the entry point located in the Browne Creek Wetlands. The Browne Creek Wetlands are located adjacent to both the Lands and the Vedder River. In order to access the Direct Pipe entry point, Trans Mountain requires temporary access through the Lands.

The CER accepted Trans Mountain's submissions that the pipeline will be installed in low-hydraulic-conductivity sediments that will provide a natural protective barrier between the pipeline and the underlying aquifer. It was of the view that open-trench construction and installing the pipeline to a depth of 1.2 meters below ground level, which meets the requirements of CSA Z662, is appropriate.

Trans Mountain committed to scheduling construction activities within the Browne Creek Wetlands during dry or very-low-flow conditions to reduce impacts on the wetlands. With commitments and Certificate conditions, the CER found that the methods of constructing the pipeline are the most appropriate.

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

The CER found that Trans Mountain's proposed timing of constructing the pipeline on the Lands is the most appropriate. The Commission is of the view, through various mitigation strategies, including the schedule for construction activities on the Lands, Trans Mountain has appropriately addressed the concerns raised by Mr. and Mrs. Enns.

Conclusion

The CER decided that Trans Mountain's proposed route is the best possible detailed route on the Lands, and the proposed methods and timing of constructing the pipeline are the most appropriate, subject to the commitments made by Trans Mountain and ongoing compliance with the Certificate OC-065 conditions.

***Trans Mountain Pipeline ULC Detailed Route Hearing MH-015-2020 – Yarrow Ecovillage Society Cooperative and City of Chilliwack***

***Pipelines - Detailed Route Hearings***

Background

The background of this proceeding is set out in this newsletter in *Trans Mountain Pipeline ULC Detailed Route Hearing MH-010-2020 – Chilliwack School District, District Parent Advisory Council, and City of Chilliwack.*

Detailed Route Hearing MH-015-2020

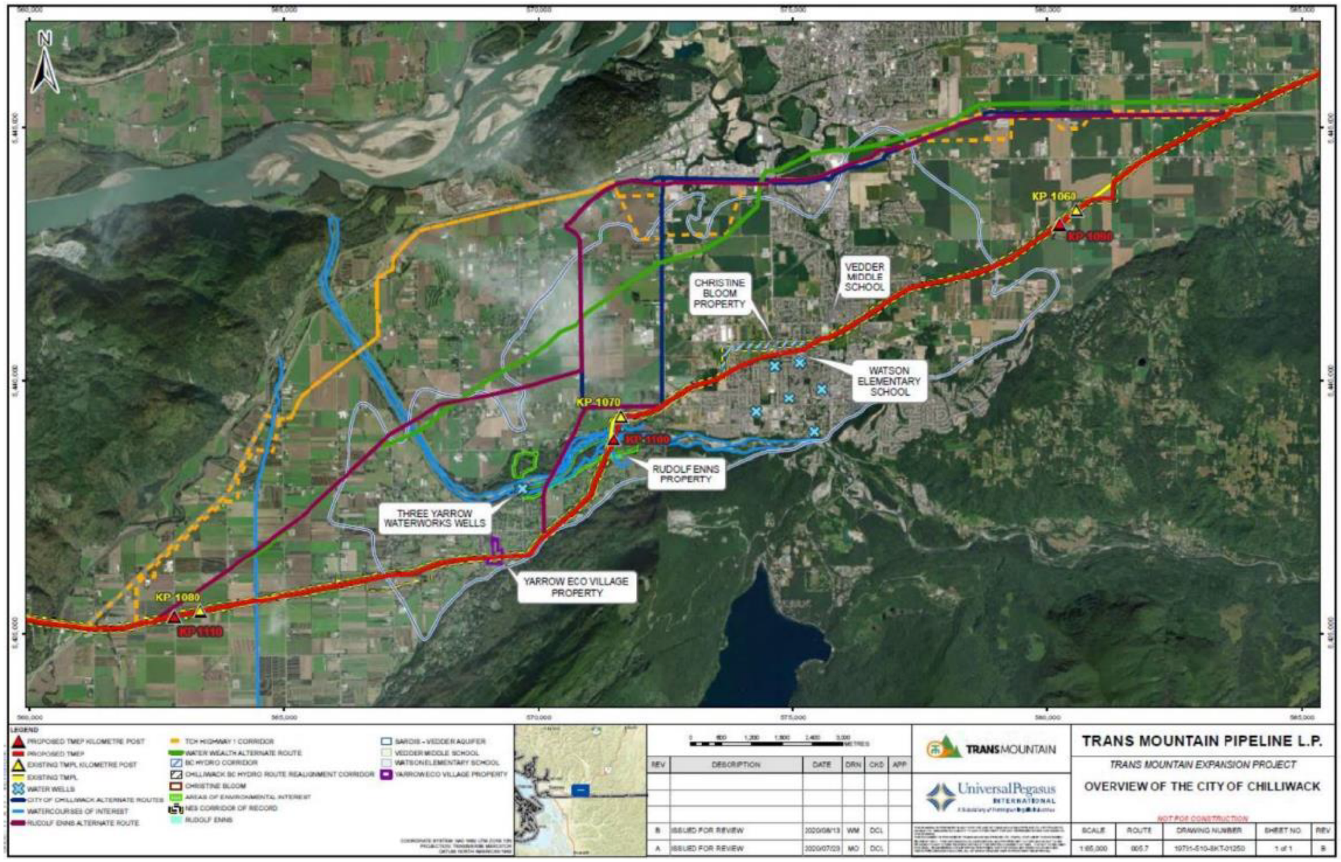
In 2017, Yarrow Ecovillage Society Cooperative ("Yarrow"), as well as four individual Yarrow members, filed statements of opposition ("SOO(s)") in relation to Tract 2438 and were granted five detailed route hearings. On 8 August 2018, the NEB combined these five hearings. Each landowner retained their individual hearing number; however, the NEB indicated that it would hold a single proceeding pertaining to Tract 2438 and would release a single decision. Pro Information Pro Environment United People Network ("PIPE UP") was granted commenter status. In September and October of 2019, Chilliwack and Yarrow filed SOOs seeking to resume 2017/2018 detailed route hearings. An SOO from an Indigenous group was submitted and withdrawn.

On 31 January 2020, the CER issued a Procedural Direction explaining that there are a number of instances where the geographical focus of one detailed route hearing overlaps with that of one or more other hearings. This Detailed Route Hearing MH-015-2020 relates to Tract 2438 in Segment 6.4 (the "Lands"). All other tracts of land in Segments 6.2, 6.3, and 6.4 are the subject of other detailed route hearings. These five hearings are referred to collectively as the "Chilliwack-Area Hearings."

Overview of the Proposed Route on the Lands

The following figure depicts Trans Mountain's proposed detailed route, as well as alternate routes proposed by the WaterWealth Project ("WaterWealth") (supported by Yarrow) and Chilliwack in the area of the Lands. It shows Trans Mountain's proposed route (in red); Chilliwack's alternate routes (in dark blue); WaterWealth's alternate route, supported by Yarrow (in green), and other features in the area of the Lands.

**Figure 3 – Trans Mountain's proposed route, Chilliwack's alternate routes, WaterWealth's alternate route, and other features in the area (C07675)**




Is Trans Mountain's Proposed Route the Best Possible Detailed Route?

In 2002, a group of people purchased Yarrow with the aim of creating a more sustainable way of living – a housing settlement incorporating an organic farm. The idea of the Ecovillage founders is that they could work with nature, enhancing soil and riparian habitats so that abundant and healthy food could be grown. The Yarrow Ecovillage Community Farm covers 20 acres of land and is certified organic. Yarrow submitted that the proposed route may imperil the Lands' certified organic status, which would significantly degrade the Yarrow brand. Yarrow farmers sell their produce to customers in local markets.

The CER found that the organic topsoil layer would be impacted by the proposed route on the Lands. However, the CER was of the view that, with the conditions imposed following the Certificate Hearings and Trans Mountain's commitments and site-specific mitigation measures, impacts on the rich organic topsoil will be appropriately mitigated.

With regard to concerns raised regarding Stewart Creek, the CER found that the proposed route will result in adverse impacts on fish and fish habitat, including the riparian habitat of Stewart Creek. The CER found the mitigation measures identified in the Pipeline EPP and the site-specific reclamation plan are appropriate to minimize the impacts on fish and fish habitat in the creek. In particular, the CER placed weight on Trans Mountain's commitment to stabilize the bed and banks of the stream channel and, at a minimum, return the bed and banks to a condition that is consistent with pre-construction conditions.

With regard to the Sardis-Vedder Aquifer, the CER found that the likelihood of impacts on Chilliwack's water supply from pipeline construction or a leak or spill on the Lands is negligible. It further found that mitigations would reduce both the likelihood of a spill and the consequences should one occur.

The CER found that Trans Mountain appropriately applied its routing criteria in this case. It noted that Trans Mountain had the onus to demonstrate that its proposed route is the best possible route and that its proposed methods and timing of construction are most appropriate. The CER found that Chilliwack's alternate routes did not differ from Trans Mountain's proposed route on the Lands and did not address Yarrow's concerns. Any advantages of these proposed Chilliwack routes would be out of the geographic scope of this detailed route hearing. With regard to the route proposed by WaterWealth that was supported by Yarrow, that route was considered in Detailed Route Hearing MH-026-2020 and was found to be inferior to Trans Mountain's proposed route.

The CER found that on a balance of probabilities, Trans Mountain's proposed route, along with the commitments and conditions that apply to it, is the best possible detailed route.

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

Trans Mountain proposed to construct the Trans Mountain Expansion Project ("TMEP") on the Lands with a conventional open-trench construction methodology. For the crossing of the watercourse on the Lands, the proposed methodology is isolated open-cut with water quality monitoring. The CER found that open-trench construction and installing the pipeline to a depth of 1.2 meters below ground level, which meets the requirements of CSA Z662, is appropriate. The CER was of the view that several of Trans Mountain's proposed mitigation measures are particularly responsive to Yarrow's interest in protecting organic soils and the requested conditions. The CER was also of the view that the mitigation measures identified in the Pipeline EPP and the site-specific reclamation plan are appropriate to protect the fish and fish habitat in Stewart Creek during construction and reclamation activities.

<u>Is Trans Mountain's Proposed Timing of Constructing the Pipeline the Most Appropriate?</u>

The CER noted that Trans Mountain expects construction activities on the Lands to occur in three phases spanning from June to September 2021 (with the reclamation of the Lands potentially extending to October 2021), subject to regulatory approval. Yarrow made no submissions on this timing, and Chilliwack's submissions were with respect to other lands. The CER found that Trans Mountain's proposed timing of constructing the pipeline across the Lands is the most appropriate.

<u>Conclusion</u>

The CER found that Trans Mountain's proposed route was the best possible detailed route on the Lands, and the proposed methods and timing of constructing the pipeline were the most appropriate, subject to the commitments made by Trans Mountain and ongoing compliance with the Certificate OC-065 conditions.

### ***Trans Mountain Pipeline ULC Detailed Route Hearing MH-026-2020 – City of Chilliwack***

***Pipelines - Detailed Route Hearings***

<u>Background</u>

The background of this proceeding is set out in this newsletter *in Trans Mountain Pipeline ULC Detailed Route Hearing MH-010-2020 – Chilliwack School District, District Parent Advisory Council, and City of Chilliwack*.

<u>Detailed Route Hearing MH-026-2020</u>

On 16 September 2020, the CER received statements of opposition ("SOO(s)") from Chilliwack seeking to resume its 2017/2018 detailed route hearing (MH-020-2018). SOOs were also filed and later withdrawn by Indigenous groups.

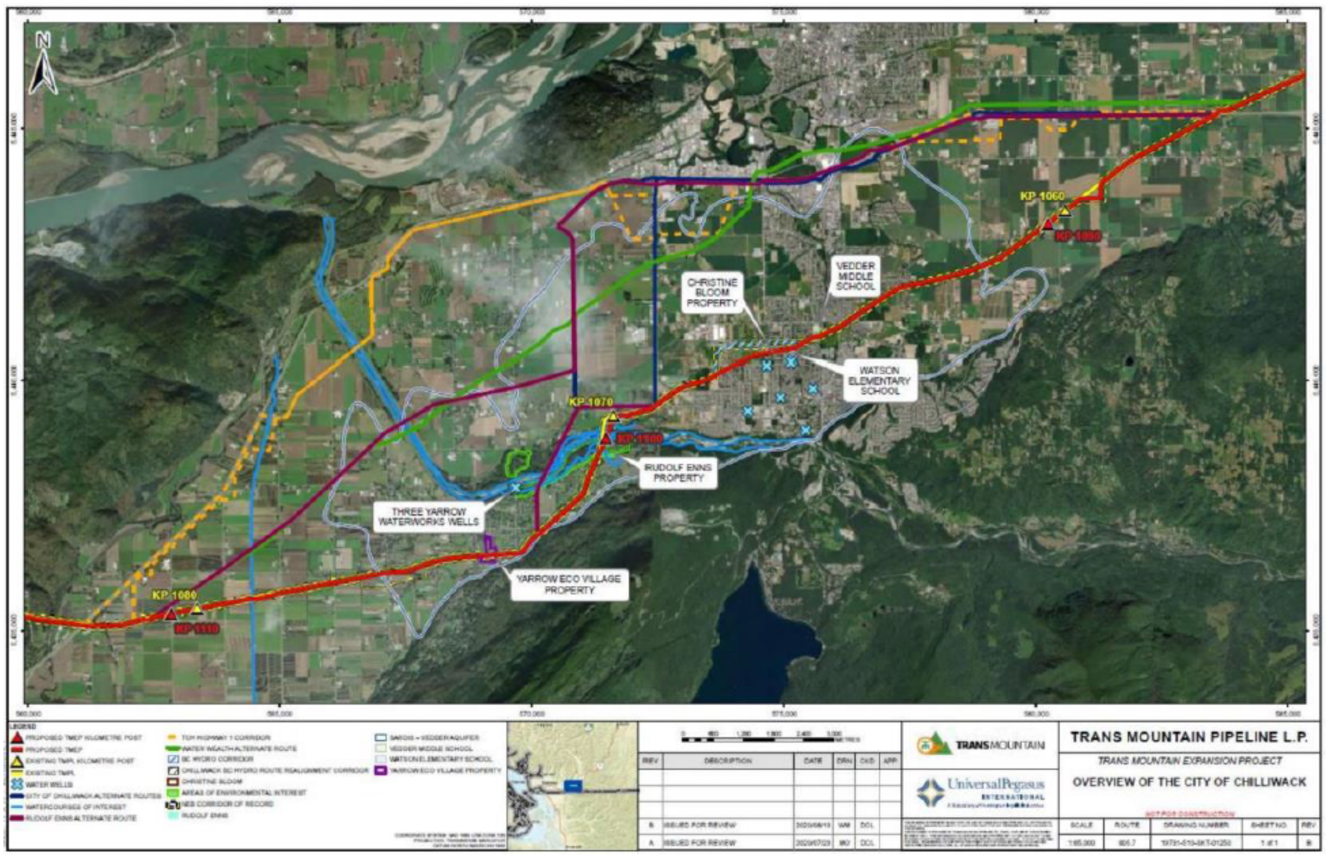
On 31 January 2020, the CER issued a Procedural Direction explaining that there are a number of instances where the geographical focus of one detailed route hearing overlaps with that of one or more other hearings. This Detailed Route Hearing MH-026-2020 relates to all tracts of land in Segments 6.2, 6.3, and 6.4, except Tracts 2307, 2352, 2410, and 2438 (the "Lands"). No decisions are being made in respect of these tracts in this Letter Decision as these lands are the subject of Detailed Route Hearings MH-010-2020, MH-011-2020, MH-013-2020, and MH-015-2020, respectively. These five hearings are referred to collectively as the "Chilliwack-Area Hearings". The CER's Letter Decisions for all Chilliwack-Area Hearings are related; they collectively decide the detailed route, methods of construction, and timing of construction for the Chilliwack area and are therefore being released concurrently.

As Chilliwack was resuming its 2017/18 detailed route hearing (MH-020-2018), the CER decided that it would bring forward and adopt the entirety of that previous record.

Overview of the Proposed Route on the Lands

The figure below shows Trans Mountain's proposed route (in red); alternate routes proposed by Chilliwack (in navy blue) and the WaterWealth Project (in green); and locations of properties:

**Figure 4 – Trans Mountain's proposed route, various alternate routes, and various properties and features in the Chilliwack area (Source: C07932)**




*How Does the Chilliwack Realignment Relate to this Proceeding?*

The CER noted that it is not reviewing the NEB's Realignment Report and subsequent GIC- approved variance of the Certificate. A detailed route proceeding is not a review of a Certificate or variance decision. However, some topics that were considered for the purpose of approving the general corridor of the Trans Mountain Expansion Project ("TMEP") (or realignment of that corridor) may also be relevant to the consideration of the proposed detailed route. Accordingly, all matters that were considered for the purpose of approving the general corridor (or realignment) are not necessarily out of scope for this detailed route hearing.

Was Trans Mountain's Notice to Chilliwack Sufficient?

Chilliwack was concerned that the notice regarding the Lands to be acquired issued to it by Trans Mountain did not meet the requirements of section 34(1)(a) of the *National Energy Board Act* ("*NEB Act*"), which was still in effect at the time of notices being issued. Chilliwack and Trans Mountain disagreed on whether Chilliwack was the owner of the Charter Lands as per section 35 of the *Community Charter* and, therefore, if it was entitled to individual notice for those Charter Lands.

Trans Mountain's proposed form and method of notice had been approved by the NEB. It included an indication that it would notify registered owners in so far as they can be ascertained. The CER determined that to comply with paragraph 34(1)(a), performing searches of the public registry is a reasonable and reliable method for ascertaining the owners of lands. These steps had been taken by Trans Mountain in notifying registered owners of land.

The CER noted that section 34 notice requirements serve to enable those whose interests in lands may be impacted to take steps to protect their interests by participating in the detailed route approval process. The CER found that the notice provided to Chilliwack by Trans Mountain achieved this objective. Further, the CER noted that Chilliwack had the opportunity throughout the hearing process to present its case regarding both its registered ownership and Charter Land interests. Chilliwack chose to limit its participation to general descriptions of the impacts on its interests rather than providing specific information to describe these potential impacts. The CER found that this was not attributable to a lack of notice, information, or opportunity but was a choice that Chilliwack made. Chilliwack suffered no prejudice in its ability to participate, and the process was procedurally fair.

Accordingly, the CER found that Trans Mountain had met the notice requirements of section 34 and that Chilliwack had not suffered prejudice in its ability to fully participate in the fair process.

Is Trans Mountain's Proposed Route the Best Possible Route?

(a) What is the risk to the Sardis-Vedder Aquifer and associated water wells?

The Chilliwack Realignment hearing included detailed consideration of risks to the Sardis-Vedder Aquifer (the "Aquifer") and Chilliwack water wells for the purpose of approving the corridor. That hearing included consideration of risks to the Sardis-Vedder Aquifer and Chilliwack water wells. In that hearing, the NEB found that for leaked or spilled oil to reach the wells a series of events had to occur. It concluded that the probability of this series occurring was not zero but minimal. The Aquifer supplies water to 98 percent of all schools and family homes in the district. This issue had been brought up and considered by the NEB. Because the Aquifer supplies water to 98 percent of schools and homes in the district, District Parent Advisory Council submitted that the TMEP should be routed away from the Aquifer and wells in the area.

With regard to the Sardis-Vedder Aquifer, the CER noted that the Chilliwack Realignment hearing considered in detail the risk that the Approved Corridor (and thus of Trans Mountain's proposed route) posed to the Aquifer and Chilliwack's water wells. The Realignment Report concluded that the risk to Chilliwack's wells is minimal, but not zero. The CER agreed. It rejected the suggestion that Trans Mountain install a trench liner, finding that it would likely introduce pipeline integrity challenges and that the TMEP leak detection system made a trench liner unnecessary.

(b) What are the potential effects on the Vedder River and adjacent ecosystems?

Concerns were raised regarding impacts on the Browne Creek Wetlands, just south of the Vedder River. Chilliwack requests a reconsideration of the route to move the pipeline away from this important and sensitive natural feature. Participants also raised concerns about risks from a pipeline spill to downstream environmental features.

The CER found that the trenchless crossing proposed by Trans Mountain is expected to avoid most adverse effects on the Vedder River and adjacent Peach Creek because it will pass beneath them. It found that the remaining effects on the surrounding environment and ecosystems will be temporary or be sufficiently and effectively addressed by Trans Mountains mitigation measures.

(c) What are potential effects on municipal infrastructure, schools, and residential areas?

Chilliwack was concerned that the route would affect municipal lands needed for infrastructure purposes and that Trans Mountain had not sought information from Chilliwack about any future infrastructure. Further concerns were raised by participants regarding impacts on schools and residences by the route and future maintenance.

The CER noted that the proposed route could impact future municipal infrastructure and could result in inconveniences to Chilliwack. However, it found that Chilliwack did not submit evidence to describe future infrastructure plans or what the impact of the proposed route would be. Similarly, the CER noted the Chilliwack had provided very little information or evidence on the impacts to its Charter Lands or utilities. Accordingly, the CER agreed with Trans Mountain that, since the TMEP would be installed within the TMPL easement, potential impacts on future municipal infrastructure will change marginally with the TMEP's installation. The CER noted its expectation of Trans Mountain to continue working with Chilliwack, as required by project conditions, to address future concerns.

The CER agreed with the findings of the Chilliwack Realignment hearing, that mitigation measures including scheduling construction activities on certain lands between the months of July and August to avoid impacts on schools, restricting access to the construction zone by fencing the entire construction area and implementing traffic management plans, proposed by Trans Mountain sufficiently addresses potential safety concerns associated with the proposed route through the Vedder Middle and residential areas within the Lands.

The CER repeated the NEB's recommendation from the Realignment Report that determined it to be acceptable to revert to the first criterion. Additionally, routing through a highly-populated area is a complex and complicated constraint mapping activity that involves weighing the interests and concerns of various stakeholders. The CER found it appropriate that Trans Mountain considered site-specific factors and its own routing guidelines in applying the routing criteria. It found that Trans Mountain had appropriately applied its routing criteria in the flexible manner required, the application of the criteria was sufficiently justified, and that site-specific criteria were considered.

(d) Considering Chilliwack's Alternate Routes, is Trans Mountain's Proposed route the Best Possible Detailed Route?

Chilliwack proposed routing the TMEP north of the Approved Corridor and either routing along Highway 1 or one of a number of other highway options. Chilliwack submitted that this would better protect the Sardis-Vedder Aquifer, Chilliwack's wells and that it would avoid crossing several municipal roads and conflicts with existing utilities.

Trans Mountain disagreed with the statement that the alternative would overlap with existing infrastructure in fewer locations. Trans Mountain also argued that Chilliwack's alternate routes are unfeasible from an engineering and constructability perspective. It argued that the routes required consent from other parties such as Telus and BC Hydro that was very unlikely to be provided. Further, the routes intersect with other infrastructure in a way that does not allow enough space to safely and efficiently construct the pipeline. The alternative routes further conflicted with other infrastructure and construction guidelines in a manner that would make construction unfeasible in some sections.

The CER found that the routes proposed by Chilliwack would effectively eliminate risks to the Chilliwack's water wells and that they would avoid certain municipal infrastructure and associated inconvenience. However, the CER determined that the issues associated with the alternate routes, particularly the feasibility issues resulting from their intersection with the BC Hydro power lines, TELUS fiber optic cables, and Ministry of Transportation and Infrastructure lands, outweighed the potential benefits.

Further, the CER agreed with Trans Mountain that the routes proposed by Chilliwack pose space constraints to the extent that would make constructing the pipeline in the area difficult to impossible without posing a risk to the intersecting infrastructure. Chilliwack's proposed routes would further contradict Trans Mountain's routing criteria by increasing land fragmentation.

*Considering WaterWealth's Alternate Route, is Trans Mountain's Proposed Route the Best Possible Detailed Route?*

WaterWealth proposed an alternate route that would run northwest of the proposed TMEP. Similar to submissions of Chilliwack, WaterWealth argued that its proposed route better protects Chilliwack's water wells. It further argued that its route is better than Trans Mountain's route for constructability and environmental, cultural, and socio-economic suitability. The alternate route would be slightly shorter, better avoids areas of significant environmental and cultural value and better minimizes routing through areas of extensive urban development. Additionally, this alternate route would avoid the Vedder River and adjacent ecosystems.

Trans Mountain argued that this route does not align with its routing criteria for various reasons, including that it does not parallel existing infrastructure for most of the route, would cause construction delays of at least two years and increase land use fragmentation, the use of previously undisturbed lands, the use of unencumbered lands. Further, the route would be unfeasible as it is not supported by Chilliwack, creates conflicts with infrastructures, does not allow for enough space to safely construct the pipeline, and relies on an unfeasible crossing of the Trans-Canada Highway.

While WaterWealth's route would avoid or even eliminate residual risks of the pipeline to the environment and Chilliwack's water wells, the CER found that Trans Mountain's route was again superior considering routing criteria, the feasibility of construction land fragmentation and potential delay.

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

Trans Mountain proposed to use open-trench and trenchless construction methodologies on different portions of the Lands to minimize disruption to landowners and environmental impact. The CER was satisfied that this approach and the proposal to limit ditch trenching for open-trench construction to the dry season minimizes potential effects on the surrounding environment and ecosystems. The CER further concluded that plans and measures committed to by Trans Mountain would appropriately minimize impacts on homes in this densely populated area of the Lands.

The CER found that Trans Mountain's proposal to limit ditch trenching for open-trench construction to the dry season minimizes potential effects on the Browne Creek Wetlands. Further, the trenchless crossings of the Vedder River, Dunville Creek, and Peach Creek minimize impacts on these features and associated ecosystems.

Trans Mountain's commitments to develop site-specific construction execution plans before starting construction activities in Segment 6.3, and to construct the pipeline based on a Heavily Restricted Construction Footprint model, appropriately minimize impacts on homes in this densely populated area of the Lands.

Considering Chilliwack's concern that it had not been given enough information on the proposed methods of construction and that approval of them was premature, the CER stated that enough information was contained in Trans Mountain's evidence to enable parties to understand the proposed methods of construction. Further, Chilliwack had had multiple opportunities to request more information from Trans Mountain, yet Chilliwack had limited its question to verifying its own belief that notice and information provided were not enough.

<u>Is Trans Mountain's Proposed Timing of Constructing the Pipeline the Most Appropriate?</u>

The CER found that Trans Mountain provided enough evidence to allow Chilliwack to predict and present evidence of the potential impacts on its municipal operations and planning during the proposed timing window. Chilliwack had provided little evidence of its own operational planning, potential plans, variable or other information that would help the CER in determining how the proposed timing of construction impacts Chilliwack's concerns.

Preparatory evidence was submitted to possibly be completed by Q1 2021, and that construction for the Charter Lands is scheduled for Q3 2021. This was within the broader timeframe for construction presented by Trans Mountain in its earlier evidence.

The CER finds that Trans Mountain's proposed timing of constructing the TMEP on the Lands is the most appropriate and reminded both parties of their respective roles in using the technical working groups to meaningfully address the timing of construction going forward.

Conclusion

The CER decided that Trans Mountain's proposed route is the best possible detailed route on the Lands, and the proposed methods and timing of constructing the pipeline are the most appropriate, subject to the commitments made by Trans Mountain and ongoing compliance with the Certificate OC-065 conditions.