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 National Energy Board ("NEB") and proceedings resulting from these energy regulatory tribunals. For further information, please contact a member of the RLC Team.

Regulatory Law Chambers 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. RLC follows a team approach, including when working with our clients and industry experts. Visit our website to learn more about RLC.

IN THIS ISSUE:

ALBERTA COURT OF APPEAL

Coaldale (Town) v Britz, 2018 ABCA 392

Permission to Appeal - Dismissed

In this decision, the Alberta Court of Appeal (the "ABCA") considered the Town of Coaldale ("Coaldale")'s application for permission to appeal the AUC's decision rendered on August 24, 2018 (the "AUC Decision"). The AUC Decision concluded that certain water, drainage, and sewer service charges levied by Coaldale did not conform to Coaldale's public utility rate structure and were improperly imposed.

The ABCA dismissed the application for permission to appeal.

Background

Doug Shields, Nadine Britz, and Eleanor Britz (the "Complainants") operated a residential property in Coaldale as a partnership. Eleanor Britz is the registered owner of the property. Although the property is zoned as single-family residential, the Complainants rent out four suites on the property to tenants. The property is therefore noncompliant, which the Complainants conceded before the AUC. While the property has only one water line and one sewer line, Coaldale has historically assessed four flat monthly service fees for water, drainage, and sewage. Effectively, Coaldale charged service fees to the property as if it consisted of four individual units. Coaldale transferred unpaid utility service amounts to the tax roll every three months for the property pursuant to section 553(1)(b) of the *Municipal Government Act* ("*MGA*"), which provides that

> "[a] council may add… to the tax roll… unpaid charges… for a municipality utility services provided to the parcel by a municipal public utility that are owing by the owner of that parcel."

The Complainants initiated an appeal under section 43(2) of the *MGA* challenging service charges applied to the property since Eleanor Britz purchased it in 2010.

Before the AUC, Coaldale argued that its approach struck a compromise that avoided forcing property owners to renovate noncompliant properties and bring them into compliance. Coaldale also submitted that the AUC did not have jurisdiction to review taxes, and therefore acted outside of its jurisdiction in reversing the charges assessed to Ms. Britz's property.

The AUC allowed the complaint in part, reversing the water, drainage, and sewer service charges applied by Coaldale within two years of the application. The AUC concluded that it was only appropriate for Coaldale to assess one flat fee for water, drainage, and sewer service, as Coaldale's bylaws did not contemplate a different rate scheme for noncompliant properties.

Grounds of Appeal

Coaldale's application raised three proposed grounds of appeal:

(a) Did the AUC act outside of its jurisdiction when it ordered the repayment of unpaid municipal utility service amounts that had been transferred to the municipal tax roll?

(b) Did the AUC err in law when it failed to consider Coaldale's broad powers under section 9 of the *MGA* to interpret its own bylaws and that Coaldale properly exercised such powers when it applied its own bylaws to this non-conforming property?

(c) Did the AUC err in law when it failed to request evidence and ignored evidence regarding the standing of the Complainants to bring the complaint?

Permission to Appeal

This appeal was before the ABCA pursuant to section 29 of the *Alberta Utilities Commission Act* ("*AUCA*"). The ABCA considered the test for permission to appeal and indicated that granting leave to appeal requires consideration of the following factors:

(a) whether the issue is of significance to the practice;

(b) whether the issue is of significance to the action;

(c) whether the appeal is *prima facie* meritorious;

(d) whether the appeal will unduly hinder the progress of the action; and

(e) the appellate standard of review that would apply if leave was granted.

Findings

The ABCA dismissed Coaldale's application for permission to appeal on the latter two proposed grounds of appeal, which the ABCA found both involved questions of mixed fact and law. As a result, the ABCA found that these grounds did not disclose issues of law that were of sufficient importance to warrant further appeal.

Section 43 of the *MGA* states that a person who uses, receives or pays for a municipal utility service may appeal a service charge, rate, or toll made in respect of it to the AUC. Section 553(1)(b) provides that municipalities can add unpaid utility service charges to the tax roll for a parcel of land. Section 553(2) of the *MGA* provides that amounts added are for all purposes to be a tax imposed under the property taxation provisions of the *MGA*.

The ABCA found that while section 553 of the *MGA* permitted the charges to be recovered as a tax, that provision did not preclude the AUC's statutory authority to review and vary utility charges.

The ABCA found that the appeal was not sufficiently meritorious under either the reasonableness or correctness standard to justify granting permission to appeal. For the purpose of this application, the ABCA determined that it was not necessary to determine which standard of review would be applied, should permission to appeal be granted.

Accordingly, Coaldale's application for permission to appeal was dismissed.

ALBERTA ENERGY REGULATOR

AER Decision Dismissing Request for Regulatory Appeal by O'Chiese First Nation of Well Licences Issued to Shell Canada Limited (Regulatory Appeal No. 1831586)

Regulatory Appeal - Denied

In this decision, the AER considered O'Chiese First Nation ("OCFN")'s request under section 38 of the *Responsible Energy Development Act* ("*REDA*") for a regulatory appeal of the AER's decisions to issue Well Licences 0475456 and 0475457 (the "Well Licences") to Shell Canada Limited ("Shell").

The AER denied OCFN's request for regulatory appeal, finding that OCFN was not eligible to request a regulatory appeal.

<u>Background</u>

OCFN is a Treaty No. 6 First Nation. OCFN stated that the lands upon which the wells were located are Crown lands subject to the terms of Treaty No. 6 and the rights of OCFN recognized by the *Natural Resources Transfer Agreement*.

<u>Legislation</u>

The applicable provision of *REDA* regarding regulatory appeals is section 38, which states that an eligible person may request a regulatory appeal of an appealable decision by filing a request for regulatory appeal with the AER in accordance with the rules.

Section 36(a)(iv) of the *REDA* defines "appealable decision" as a decision of the Regulator that was made under an energy resource enactment if that decision was made without a hearing. "Eligible person" is defined in section 36(b)(ii) of *REDA* as a person who is directly and adversely affected by a decision referred to in clause 36(a)(iv).

<u>Reasons for Decision</u>

The AER determined that the decision was an appealable decision. However, the AER found that OCFN was not "a person who is directly and adversely affected."

Appealable Decision

The Well Licences applications were filed pursuant to the *Oil and Gas Conservation Act*, which is an energy resource enactment as defined under the *REDA*, and were approved without a hearing. Therefore, those decisions were appealable decisions.

Directly and Adversely Affected

The AER found that OCFN did not provide the information that was needed to establish that OCFN or its members were directly and adversely affected by the AER's decisions to issue the Well Licences. The AER noted that OCFN took the position that it was not required to provide any detailed information regarding impacts to the First Nation.

The AER explained that it must consider whether there is a "degree of location or connection" between the work proposed and the person, and whether that connection is sufficient to demonstrate the person may be directly adversely affected by the proposed activity (citing the Alberta Court of Appeal ("ABCA") in *Dene Tha' First Nation v. Alberta (Energy and Utilities Board)*).

Specifically, the AER found that:

(a) OCFN failed to demonstrate the required degree of location or connection between the Well Licences and a potential for direct and adverse impacts on the OCFN or its members to establish that the OCFN was an "eligible person" under section 38 of *REDA*;

(b) OCFN merely asserted rights without detailing how those rights were connected to locations within or in proximity to the surface locations of the wells, which was not sufficient;

(c) the ABCA rejected a similar position taken by OCFN in *O'Chiese First Nation v. Alberta Energy Regulator*, 2015 ABCA 348, where the ABCA found that a mere assertion was not sufficient to establish that a person was directly and adversely affected, and that evidence of "directly and adversely affected" must be adduced; and

(d) none of the information provided by OCFN showed if or how its members were present or active at locations within or in proximity to the surface locations of the wells approved by the AER.

<u>Failure to Consider the Rocky Exploration Project as One Project</u>

The AER also rejected OCFN's submission that in discharging its obligations to consider the potential adverse impacts on OCFN, the AER should have considered the Well Licences applications in the context of all of Shell's Rocky Exploration Project applications, as a single energy resource project. OCFN stated that it is clear that the public land dispositions are part of an overall scheme to develop what Shell described as its "Rocky Exploration Project."

The AER noted that it has discretion under section 30(2) of *REDA* to combine applications where the AER considers it appropriate; however, it is not required to do so.

Summary

The AER denied the request for regulatory appeal, based on finding that OCFN was not directly and adversely affected by the AER's decisions to issue the Well Licences and, therefore, not an "eligible person" as defined by section 36(b)(ii) of *REDA*.

AER Bulletin 2018-32: New Edition of Directive 017: Measurement of Requirements for Oil and Gas Operations

Conventional - Unconventional - Thermal In Situ

In this Bulletin, the AER announced the release of a new edition of *Directive 017: Measurement Requirements for Oil and Gas Operations* with revised measurement requirements for conventional, unconventional, and thermal in situ operations.

The AER indicated that the new requirements reflect advancements in measurement technology and in emerging unconventional resource plays. The changes give industry more flexibility in selecting measurement approaches, resulting in reduced capital and operating costs without compromising accurate measurement reporting.

The updated directive replaced the edition released on March 31, 2016, and takes effect immediately.

AER Bulletin 2018-33: Reporting Related to Closure Activities and Directive 039 *Moving to OneStop*

Updates to Reporting

As of November 29, 2018, the following reports must be submitted through OneStop, the AER's online submission tool:

- reports related to well suspensions (initial suspension, industry inspections, and reactivation); previously submitted through the Digital Data Submission ("DDS") system;
- reports related to facility and well surface abandonment; previously submitted through the DDS system;
- updates to working interest participant information;
- the annual dehydrator benzene inventory form (inventory) for actual past calendar year performance as per the current *Directive 039: Revised Program to Reduce Benzene Emissions from Glycol Dehydrators;* and
- area-based closure required and voluntary submissions related to remediation, progressive reclamation, and closure spend.

There are prerequisites to submit these reports through OneStop, as set out in this Bulletin.

AER Bulletin 2018-34: Updated Alberta Environment and Parks Master Schedule of Standards and Conditions

Updates - Public Lands Act - In Situ - Reservoir - Geophysical

In this Bulletin, the AER announced that on November 22, 2018, Alberta Environment and Parks ("AEP") updated the *Master Schedule of Standards and Conditions* ("*MSSC*"). This affects all AER applications under the *Public Lands Act*. This update included three new sections covering the themes in situ, reservoir, and geophysical.

The Landscape Analysis Tool ("LAT"), *Alberta Public Lands Glossary of Terms*, *Pre-Application Requirements for Formal Dispositions*, and Table A2 in the *Public Lands Administrative Regulation* have been updated to align with the updated standards and conditions. LAT reports are valid for 120 days from the date they were run and will continue to be accepted.

ALBERTA UTILITIES COMMISSION

Express Pipeline Ltd. Application Pursuant to Section 117(1)(a) of the Electric Utilities Act for an Exemption (AUC Decision 23394-D01-2018)

Electric Utility

In this decision, the AUC considered Express Pipeline Ltd. ("Express")'s application to exempt a transmission line that it proposed to construct and operate (the "Proposed Express Line") as well as the electric energy it would transmit, from the definition of "electric utility" in section 1(1)(o) of the *Electric Utilities Act* (the "*EUA"*).

The AUC denied Express' application, based on its finding that, although section 117(1)(a) enables the AUC to make rules exempting "any facility or class of facilities from the definition of electric utility" under the *EUA*, the AUC had not enacted any such rules to provide for these exemptions. In the absence of such rules, the AUC found that it lacked the authority to grant the requested exemption.

<u>Background</u>

The Proposed Express Line would be a 69 kilovolt, three-phase radial power line mounted on single poles. It would be wholly situated in Alberta with a connection point near the border between Alberta and Montana that would connect to a transmission line currently owned and operated by Hill County. The electric supply would not come from the Alberta Power Pool. Instead, the Proposed Express Line would transmit power generated in the U.S. to the electric motors and auxiliaries at the Wildhorse Station, and all of its capacity would be reserved for use by Express.

<u>Findings</u>

The AUC rejected both propositions on which Express based its exemption request, namely:

(a) its expectation that the AUC had the authority to grant an exemption order similar to Order U98075 issued in 1998 by the Alberta Energy and Utilities Board (the "EUB"), granting TransCanada's application for an exemption; and

(b) that Express owning and operating its own transmission line was its only reliable and economically viable alternative to ensure it received the service it required at the Wildhorse Station.

No Rules Authorizing AUC to Grant Exemption

The AUC found that although *EUA section* 117(1)(a) enables the AUC to make rules exempting "any facility or class of facilities from the definition of electric utility" under the *EUA*, the AUC did not enact any rules to provide for these exemptions. In the absence of such rules, the AUC lacked the authority to grant the requested exemption.

The AUC noted that, in making that finding, the EUB did not consider any particular rule nor did it discuss the need to create a rule to grant the exemption requested. As such, the board did not consider any particular rule nor did it discuss the need to create a rule to grant the exemption requested. As such, the AUC did not consider the EUB's findings in Order U98075 to be helpful or persuasive in its consideration of Express' application.

Means by Which Express May Receive the Service It Requires

The AUC considered that as the owner of the Wildhorse Station, Express satisfied the definition of a border customer under the *Isolated Generating Units and Customer Choice Regulation*. The AUC determined that Division 5 of the *Isolated Generating Units and Customer Choice Regulation* prescribed the means by which Express may have received the service it required at the Wildhorse Station, as follows:

(a) section 101(1) of the *EUA* required Express to approach FortisAlberta Inc. ("Fortis") the owner of the electric distribution system where the Wildhorse Station was located to make arrangements for electric energy; and

(b) section 15 of the *Isolated Generating Units and Customer Choice Regulation* obliged Fortis to "make arrangements for the provision of electric energy" to a border customer located within its service area.

<u>Summary</u>

As the AUC did not establish rules that would allow for the requested exemption, and since the *Isolated Generating Units and Customer Choice Regulation* prescribed the means by which Express could receive electric energy, the AUC denied Express' application for an exemption.

Alberta Electric System Operator Rejection of Reliability Standard MOD-026-1 (AUC Decision 23917-D01-2018)

Reliability Standard - Rejected

In this decision, the AUC rejected the adoption of reliability standard MOD-026-1 in Alberta, pursuant to section 19(6) of the *Transmission Regulation*.

Background

The Alberta Electric System Operator ("AESO") recommended that the AUC assess the reliability standard MOD-026-1 in the category of modelling, data, and analysis.

In Alberta, the AESO fulfils the role and obligations of Independent System Operator ("ISO") as defined in the *Electric Utilities Act*.

Pursuant to section 19(4) of the *Transmission Regulation*, before adopting or making reliability standards, the AESO must consult with those market participants that it considers likely to be affected and it must forward the reliability standards to the AUC for review. The AESO also provides the AUC with a recommendation to approve or reject each of them.

Pursuant to sections 19(5) and 19(6) of the *Transmission Regulation*, the AUC must approve or refuse to approve each reliability standard in accordance with the recommendation of the ISO, unless an interested person satisfies the AUC that the ISO's recommendation is:

(a) technically deficient, or

(b) not in the public interest.

In this instance, no objections were filed with the AUC.

AESO Recommendation to Reject Standard

The AESO recommended that the AUC reject the NERC MOD Standard, based on the following:

(a) the purpose of the North American Electric Reliability Corporation ("NERC") reliability standard MOD-026-1 ("NERC MOD Standard") was fulfilled by existing ISO rules, in particular, section 502.5 *Generating Unit Technical Requirements*, section 502.6 *Generating Unit Operating Requirements* and the associated Generating unit functional document submission form;

(b) the existing ISO rules have broader application and are more stringent regarding testing requirements than the NERC MOD Standard; and

(c) the NERC MOD Standard would impose a reporting requirement on legal owners of generating units, something that is already done on a voluntary basis. For all these reasons, the AESO recommended that the NERC MOD Standard be rejected and assessed as not applicable in Alberta.

No formal consultation with market participants was undertaken as the AESO expressed the view that market participants were not likely to be directly affected by the proposed rejection of the NERC MOD Standard.

AUC Findings

The AUC rejected the adoption in Alberta of the NERC MOD Standard, pursuant to section 19(6) of the *Transmission Regulation*, and based on the ISO's recommendation.

The AUC accepted and relied on the AESO's assertion that no market participant was likely to be affected by the rejection of the NERC MOD Standard and that no formal consultation was required.

FortisAlberta Inc. 2017 Annual Transmission Access Charge Deferral Account True-Up (AUC Decision 23834-D01-2018)

Deferral Account Reconciliation - System Access Service

In this decision, the AUC approved FortisAlberta Inc. ("Fortis")'s 2017 annual transmission access charge deferral account ("TACDA") and the 2017 TACDA true-up net refund amount of $10.927 million.

Background

All electric distribution companies accessing the electric transmission system in Alberta are charged by the Alberta Electric System Operator (the "AESO") for transmission services provided in relation to customers in their distribution service areas.

2017 TACDA True-Up Amount

The 2017 TACDA true-up amount included the true-up of a 2015 rider related to the AESO charges, the true-up of the four amounts arising from the various 2017 AESO charges (i.e., the system access service deferral true-up, AESO deferral account reconciliation true-up, Balancing Pool true-up and border customer deferral account true-up), and carrying costs associated with those amounts.

2015 TACDA Rider True-Up

The AUC explained that the purpose of a deferral account rider true-up is to ensure that, for each of the AESO charges, the amounts actually collected or refunded equal the amounts approved by the AUC. Fortis calculated the amount of the rider true-up as the difference between the 2015 annual TACDA true-up refund of $2.899 million, approved in Decision 21787-D01-2016, and the actual amount refunded of $1.956 million, resulting in the true-up of $0.943 million on an aggregate basis. The deferral account rider true-up amount was determined for each rate class as the difference between the amount approved for collection or refund by rate class and the amount actually collected or refunded for each rate class.

The majority of the $0.943 million 2015 TACDA rider true-up amount was driven by the difference between forecast and actual consumption for the irrigation rate class in 2017 when the 2015 TACDA rider was in place.

System Access Service Deferral True-Up

The AUC explained that the purpose of a system access service deferral true-up is to reconcile the actual transmission access revenue received from customers to the actual transmission access costs paid to the AESO.

Fortis indicated that its 2017 actual transmission access costs, excluding transmission costs for transmission-connected Rate 65 customers, were $579.019 million, while its actual transmission access revenues for distribution connected customers, including revenues received through its quarterly TACDA riders, were $588.847 million. Therefore, Fortis applied to refund $9.829 million to customers.

AESO Deferral Account Reconciliation True-Up

Under section 14(3) of the *Electric Utilities Act* (“*EUA*”), “the Independent System Operator [(“ISO”)] must be managed so that, on an annual basis, no profit or loss results from its operation.” Accordingly, any variances between the actual costs the AESO incurs and the forecast amounts, are refunded to or recovered from market participants by way of the AESO deferral account reconciliation, typically undertaken on an annual basis. In turn, the electric distribution companies flow-through these collections or refunds to customers in their service areas.

Balancing Pool True-Up

Under section 82 of the *EUA*, each year, the Balancing Pool is required to forecast its revenues and expenses to determine any excess (or shortfall) of funds. Based on this forecast, the Balancing Pool determines an annualized amount that will be refunded to (or collected from) electricity consumers over the year. This is “… so that no profit or loss results, after accounting for the annualized amount under section 82(7) as a revenue or expense of the Balancing Pool.” This consumer allocation amount applies to all market participants who receive system access service from the AESO and is recovered through Rider F of the ISO tariff. The consumer allocation is based on the amount of electric energy consumed annually. In 2017, the Balancing Pool collected a consumer allocation of $1.10 per megawatt hour (“MWh”).

Border Customer Deferral Account

Border customers are customers in Fortis’ service area that receive energy through a connection to a distribution or transmission system located outside Alberta. The purpose of the border customer deferral account is to capture the net differences between Fortis’ receipts and payments pertaining to transactions related to the extra-provincial supply of energy and wires services to border customers in accordance with section 16 of the *Isolated Generating Units and Customer Choice Regulation.*

Fortis allocated the border customer deferral account amounts to all rate classes based on their 2017 actual energy consumption.

Carrying Costs

Fortis calculated carrying costs on outstanding amounts related to the true-up balances in accordance with Rule 023: *Rules Respecting Payment of Interest*. The rate used was the Bank of Canada monthly bank rate plus 1.5 percent. Fortis calculated a weighted average Bank of Canada rate for months in which the interest rates changed. The total carrying costs amounted to a net refund of $0.548 million. Fortis allocated carrying costs to rate classes in proportion to their deferral account balances.

<u>Findings</u>

The AUC approved a net refund of $10.927 million, as calculated by Fortis and the resulting true-up amount for each rate class.

The AUC found Fortis’ application to be consistent with the framework previously approved in Decision 3334-D01-2015. The AUC found Fortis’ calculation of the amounts comprising the 2017 annual TACDA true-up were reasonable. The AUC also found the individual components of the 2017 TACDA true-up to rate classes consistent with previously approved methodologies and were reasonable.

ENMAX Power Corporation 2017 Annual Transmission Access Charge Deferral Account True-Up (AUC Decision 23817-D01-2018)

Transmission Access Charge Deferral Account Rider

In this decision, the AUC considered ENMAX Power Corporation ("ENMAX")'s application for a net 2017 transmission access charge deferral account ("TACDA") collection from customers of $31,404,372. ENMAX proposed to collect its 2017 TACDA true-up amount by way of a transmission access charge rider effective from January 1, 2019, to December 31, 2019.

The AUC approved ENMAX's 2017 TACDA true-up net collection amount of $31,404,372, effective January 1, 2019.

<u>Background</u>

All electric distribution companies accessing the electric transmission system in the province are charged by the Alberta Electric System Operator ("AESO") for transmission services provided in relation to customers in their distribution service areas. The purpose of ENMAX's annual TACDA true-up application is to ensure that the revenues collected through its transmission access charges in a year recover the AESO tariff charges that ENMAX pays to the AESO in that year.

In accordance with the provisions of the performance-based regulation ("PBR") framework approved in Decision 21149-D01-2016 (Errata), ENMAX's TACDA was a dollar-for-dollar flow-through of the AESO tariff charges for the duration of its 2015-2017 PBR term. In other words, the utility does not assume any volume risk in flowing through AESO-related costs to customers.

<u>2017 TACDA True-Up Amount and Transmission Access Charge Rider Rate</u>

The components of the 2017 TACDA true-up amount include the true-up of the portion of the 2015 transmission access charge rider, the true-up of the three amounts arising from various 2017 AESO charges (i.e., the system access service deferral true-up, AESO deferral account reconciliation true-up and Balancing Pool true-up) and carrying costs associated with the 2015 true-up amounts.

2015 Transmission Access Charge Rider True-Up

The purpose of deferral account rider true-ups is to ensure that the amounts collected or refunded in total equal the amounts approved by the AUC. In this proceeding, ENMAX requested approval to reconcile its 2015 Transmission Access Charge ("TAC") rider true-up amounts.

ENMAX proposed to true-up the remaining portion of the 2015 TAC rider less amounts ENMAX previously recorded. ENMAX calculated the total collection for this portion to be $1.254 million. ENMAX incorporated this collection into the TAC rider adjustment.

ENMAX determined the deferral account rider true-up amount for each rate class as the difference between the amount approved for collection or refund by rate class, and the amount actually collected or refunded for each rate class.

System Access Service Deferral True-Up

The purpose of a system access service deferral true-up is to reconcile the actual transmission access revenue received by ENMAX from its customers through both the base system access service rates and quarterly TAC true-up riders, to the actual transmission access costs paid to the AESO. In the application, ENMAX included two components in its 2017 system access service deferral true-up: (1) the reconciliation of 2017 quarterly TAC riders and; (2) the 2017 TAC deferral true-up.

ENMAX calculated its 2017 system access service deferral true-up as the difference between the actual transmission costs of $315.119 million and the sum of system access service base revenue and quarterly TAC revenue of $166.971 million and $119.870 million, respectively. The result was a net collection from customers of $28.278 million.

ENMAX allocated the AESO costs to customers, based on its cost-of-service methodology, previously approved by the AUC. ENMAX did not allocate AESO costs to customers under its "D600 distribution tariff large distributed generation" and "D700 distribution tariff transmission connected" rate classes, which were billed on a flow-through basis.

AESO Deferral Account Reconciliation True-Up

ENMAX did not receive an AESO deferral account reconciliation invoice prior to filing the application. Therefore, no AESO deferral account reconciliation true-up amounts were included in ENMAX's 2017 TACDA.

Balancing Pool True-Up

Each year, the Balancing Pool is required under provisions of the *EUA* to forecast its revenues and expenses to determine any excess (or shortfall) of funds. Based on this forecast, the Balancing Pool determines an annualized amount that will be refunded to (or collected from) electricity consumers over the year, "… so that no profit or loss results, after accounting for the annualized amount under section 82(7) as a revenue or expense of the Balancing Pool." This amount, known as the consumer allocation, applies to all market participants who receive system access services from the AESO and is recovered through Rider F of the Independent System Operator ("ISO") tariff. In Decision 22264-D01-201613, the AUC approved ENMAX's Balancing Pool rider effective January 1, 2017. This resulted in a $1.10 per megawatt hour collection from customers in 2017.

The purpose of ENMAX's Balancing Pool true-up is to ensure that its Balancing Pool refund to or collection from its customers matches its settlement with the AESO. In 2017, ENMAX paid $10.665 million in Balancing Pool allocations that were then flowed through to ENMAX's customers. Due to the difference between forecast and actual billing determinants, ENMAX collected $10.694 million from its customers in 2017, necessitating a net refund of $0.029 million. ENMAX allocated the Balancing Pool true-up to customer rate classes in proportion to the actual energy consumed by each rate class in 2017. ENMAX did not allocate the true-up amount to Rate D600 and Rate D700 customers that were billed on a flow-through basis since metering and billing of the Rate D600 and Rate D700 customers ensured that the amounts billed to those customers were consistent with $1.10 per megawatt hour collection.

Carrying Costs

ENMAX calculated carrying costs on outstanding amounts related to the true-up balances in accordance with Rule 023: *Rules Respecting Payment of Interest*. The rate used was the Bank of Canada monthly bank rate plus 1.5 percent. ENMAX calculated a weighted average Bank of Canada rate for July 2017, as the Bank of Canada monthly bank rate changed during that month. ENMAX calculated the total carrying costs to be a net collection of $1.902 million. ENMAX allocated carrying costs to rate classes in proportion to their respective deferral balances.

<u>AUC Findings</u>

The AUC approved ENMAX's 2017 transmission access charge deferral account rider, effective January 1, 2019.

The AUC found that on a total bill basis, bill impacts were less than 10 percent, a threshold the AUC determined in past decisions to be indicative of possible rate shock. Therefore, the AUC found the rate impacts were reasonable and unlikely to cause rate shock.

AUC Bulletin 2018-15: Stakeholder Consultation for Specified Penalties, on AUC Rule 021: Settlement System Code Rules and Rule 028: Natural Gas Settlement System Code Rules

Proposed Changes - Written Comments - Rule 021 - Rule 028

In this Bulletin, the AUC invited written comments from interested persons on proposed changes to *Rule 021: Settlement System Code Rules* ("Rule 021") and *Rule* 028: *Natural Gas Settlement System Code Rules* ("Rule 028"). The proposed changes to Rule 021 and Rule 028 are the result of the consultation undertaken by AUC staff with representatives of wire service providers (including rural electrification associations and municipally-owned utilities), natural gas distributors, load settlement agents, meter data managers, retailers and billing agents, as well as with staff of the Office of the Utilities Consumer Advocate and of the Alberta Electric System Operator.

During the next phase of developing the regulatory framework to implement specified penalties for customer care and billing rules, the AUC will make rules and set specified penalties.

AUC Bulletin 2018-16: Consultation on Specified Financial Penalties for Utility Customer Care and Billing Issues

Bill 13 - Electricity - Rule 003 - Proposed Changes

In this Bulletin, the AUC invited written comments from interested persons on the proposed new *Rule 032: Specified Penalties for Contravention of AUC* Rules ("Rule 032") and the proposed revisions to Rule 003: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers and Default Supply Providers* ("Rule 003").

On June 11, 2018, Bill 13: *An Act to Secure Alberta's Electricity Future* ("*Bill 13*") came into force, which empowered the AUC to apply financial penalties to entities violating an AUC order, rule or decision.

In Bulletin 2018-13, the AUC outlined a two-phase process for developing the specified penalties framework contemplated in Bill 13. In Phase 1, the AUC reviewed and consulted with stakeholders on the current AUC rules that relate to customer care and billing. This process set the requirements and obligations around the roles and responsibilities of entities involved in the customer enrolment and de-enrolment process. The AUC stated that it is continuing with the review and strengthening of AUC customer care and billing rules through two initiatives.

First, by proposing changes to AUC Rule 003 to align with new provisions in the *Electric Utilities Act* and *Gas Utilities Act* allowing the AUC to establish service quality standards for owners of electric utilities, gas utilities, regulated service providers and retailers. The AUC explained that revisions to Rule 003 would set out certain billing and customer care requirements for these entities, including rural electrification associations, municipally-owned electric utilities, and competitive retailers.

Second, concurrent with the review of Rule 003, the AUC is introducing Rule 032. Rule 032 sets out the specific financial penalties for contraventions of the AUC rules listed in the penalty table of the rule.

AUC Announcement: Remembering William Andrew Grieve (November 21, 2018)

In Remembrance

In this announcement, the AUC announced that their recently retired chair, William Grieve, passed away on the evening of November 20, 2018.

There were many facets of Mr. Grieve that made him an inspiration to those at the AUC, and so well respected and liked.

With a remarkable intellect and unparalleled work ethic, Mr. Grieve was not only tremendously competent as the AUC's first permanent chair but as a visionary that inspired the organization and many of its staff to accomplish extraordinarily challenging goals. Mr. Grieve's imprint can be seen across the current state of utility regulation in Alberta and beyond.

Mr. Grieve was a remarkable leader at the AUC and within Alberta's regulatory sphere, but his service to the community went much further than that, including senior governance roles with the Canadian Association of Members of Public Utility Tribunals, MacEwan University, Concordia University College, Edmonton's Fringe Theatre Adventures, and the Edmonton Eclipse Junior A Lacrosse Club.

Mr. Grieve's professional accomplishments were also outstanding. His formative time and role at the AUC was followed by: a senior regulatory affairs role at TELUS Corp.; being general counsel of the Saskatchewan Public Utilities Review Commission; as the special assistant to the federal minister of Energy, Mines and Resources; being an advisor to the government of Saskatchewan; being chair of the Saskatchewan Communications Network; acting as counsel to the Federal-Prairie Task Force on Telecommunications Regulation; and being a consultant to the Stentor Companies and the Canadian Radio-television and Telecommunications Commission. In December 2011, Mr. Grieve was appointed as Queen's Counsel for his outstanding contributions to the legal profession and his community.

The AUC expressed how much it will miss Mr. Grieve's warm, friendly, and caring personal nature, his innate intellectual curiosity, extraordinary analytical skills, commitment to honourable principles in like and in work. Mr. Grieve instilled a special culture to those at the AUC - a culture of fairness, responsibility, public service, discipline, intellectual rigour, and innovation.

Commission-Initiated Review and Variance of Decision 22741-D01-2018 (AUC Decision 23505-D01-2018)

Capital Tracker True-Up - PBR Regulation - AESO Contributions Program

In this decision, the AUC decided to rescind its direction in paragraph 138 of Decision 22741-D01-2018 (the "Original Decision"). In that decision, the AUC issued a direction to FortisAlberta Inc. ("Fortis") on how to finalize the Alberta Electric System Operator ("AESO") Contributions Program amounts to enable Fortis' transition to the 2018-2022 performance-based regulation ("PBR") plan.

<u>Background</u>

The Original Decision

In the Original Decision, the AUC determined Fortis' 2016 capital tracker true-up application. One of the capital tracker true-up programs under consideration was Fortis' AESO Contributions Program. The AESO Contributions Program recognized the cost to Fortis of contributions paid to the AESO for the construction of transmission facilities that had been approved by the AUC and were found to be required to supply load growth in Fortis' distribution area.

The AUC approved an incremental capital funding mechanism for the 2018-2022 PBR term that divided capital into two categories: Type 1 and Type 2.

The AUC determined that Type 2 capital would be managed under a K-bar mechanism, which provided a base amount of capital funding determined using the average level of actual expenditures for the period 2013 to 2016 and the notional 2017 closing rate base as a starting point.

The K-bar amount would be adjusted annually to account for the effects of inflation and productivity growth (I-X), growth in billing units (Q), and changes to the weighted average cost of capital. The determination of base amount funding for Type 2 capital required a determination of the final approved capital expenditure amounts for the years prior to 2018.

Funding for Fortis' AESO Contributions Program fell within Type 2 capital subject to K-bar. Therefore, it was necessary to determine the final amounts for this program for the years 2013-2017.

In the Original Decision, the AUC acknowledged the difficulties in truing up the AESO Contributions Program, noting that AESO contribution amounts on projects were subject to ongoing update and revision as project timing, design and cost estimates changed over time. However, Fortis' transition to the next generation 2018-2022 PBR plan, which no longer employed the same capital tracker mechanism, might necessitate a determination of final 2013-2017 project costs, prior to the actual AESO contribution amounts being determined in subsequent transmission facility owner and Fortis capital-related true-up proceedings.

Therefore, in the Original Decision, the AUC directed Fortis to finalize its AESO Contributions Program amounts to enable its transition to the 2018-2022 PBR plan. Specifically, the AUC directed Fortis to recalculate the AESO contributions to reflect the refund that Fortis would be eligible for if it immediately increased Demand Transmission Service ("DTS") to the amount of the maximum capacity of the project, and then to calculate the effect of such DTS contract capacity changes to determine a revised prior-year true-up for the year 2016.

Compliance Filing

Fortis' compliance filing to the Original Decision (AUC Proceeding 23372), revealed that the directed recalculation would result in a net reduction of $169 million in capital additions for 2016. Fortis submitted that incorporating this into its notional 2017 revenue requirement and 2018 K-bar amounts would generate "anomalous" results and result in a significant administrative burden.

<u>Review Decision</u>

Section 10 of the *Alberta Utilities Commission Act* authorizes the AUC to review any decision or order made by it and, after the review, to confirm, rescind, or vary the decision or order.

In this review decision, the AUC found that the outcome of the approach directed in the Original Decision did not fairly balance the interests of both ratepayers and Fortis. The AUC accepted Fortis' submissions that complying with the direction would result in a significant administrative burden and a net reduction of $169 million in capital additions for 2016.

Fortis' Hybrid Deferral Account Proposal

Fortis proposed a hybrid deferral account, which involved a deferral mechanism for determining final changes to AESO contribution amounts up to the end of the 2013-2017 PBR term and the establishment of incremental K-bar funding for the 2018-2022 PBR term.

Under this approach, customers received refunds associated with historical AESO contributions they paid for through capital tracker mechanism. New investments were subject to the incentives inherent in the K-bar mechanism. The AUC found that this approach was also consistent with the general treatment of costs subject to capital tracker treatment during the 2013-2017 PBR term as well as the overall 2018-2022 PBR framework.

Fortis proposed that projects, including any project changes, that were issued a permit and licence prior to, or during, the 2013-2017 PBR term would be subject to a true-up through a deferral account.

The 2018 base K-bar amount would also be adjusted as a result of the going-in rate base being incorporated into the calculation of the deferral account. Fortis confirmed that its hybrid deferral account proposal would not have any mechanism to refund customers should Fortis receive any refund from the AESO with respect to projects completed after 2017.

Fortis also noted that the 2017 closing rate base and 2018 revenue from the PBR formula would be subject to a one-time true-up following finalization of Fortis' notional rebasing amounts. Similarly, the 2018 net additions based on the four-year average of actual approved amounts from 2013 to 2016 would be subject to a one-time true-up following the approval of any outstanding actual refunds or costs related to AESO contributions made in the 2013-2017 PBR term.

For purposes of the deferral account calculations, Fortis would apply the annual adjustments for refunds or costs related to the AESO contributions made during the 2013-2017 term to the historical rate base (i.e., the 2017 closing rate base) associated with the AESO Contributions Program. The difference between the revenue collected through going-in rates (escalated each year by I-X and Q) and the revenue requirement associated with related true-ups would form the deferral true-up amount.

AUC Findings

The AUC directed Fortis to implement the hybrid deferral account approach for its AESO Contributions Program amounts, finding that this approach best balanced the interests of customers and Fortis.

The AUC found that Fortis' hybrid deferral account approach would ensure that past prudent investments were properly accounted for in current and future rates. The AUC did not consider the annual true-up to be overly burdensome because these deferral account true-ups would be combined with other true-ups as part of the annual PBR rate adjustment filings.

The AUC recognized that this approach had the benefit of not requiring Fortis to make any changes to the K-bar calculation mechanics.

Summary

The AUC varied its direction from the Original Decisions and directed that Fortis use its proposed hybrid deferral account approach to account for amounts relating to the AESO Contributions Program. Under this approach, projects that received a permit and licence prior to December 31, 2017, shall be given deferral account treatment provided that the AUC approved the need, scope, level and timing and associated costs for the project as part of a capital tracker review. Projects that receive a permit and licence after December 31, 2017, shall be managed under the incentive properties of K-bar.

Once the AUC reaches a determination on the finalized 2016 and 2017 capital tracker amounts, Fortis will be directed to use the approved amounts to finalize its 2016 and 2017 capital tracker true-ups and adjust its going-in rates and K-bar amounts for its 2018-2022 PBR plan.

Alberta Electric System Operator 2016 Deferral Account Reconciliation (AUC Decision 23802-D02-2018)

AESO Net Deferral Account Settlement - Surplus

In this decision, the AUC considered the Alberta Electric System Operator ("AESO")'s application requesting to settle its 2016 net deferral account surplus with market participants, in the amount of $26.2 million.

The AUC approved the settlement of the deferral account balances as applied for by the AESO.

Application Details

Pursuant to sections 30 and 119 of the *Electric Utilities Act ("EUA")*, the AESO filed an application with the AUC requesting approval of its determination of deferral account balances for 2016 and changes to deferral account balances for 2010 through 2015.

The deferral account balance resulted from differences between costs the AESO incurred in providing system access service and the revenues recovered through rates charged to customers in prior periods.

Section 14(3) of the *EUA* states that the Independent System Operator ("ISO") must be managed so that, on an annual basis, no profit or loss results from its operation.

The AESO requested the AUC approve the deferral account balance reconciliations for the calendar years 2016 through to 2010 consisting of:

- a shortfall of $180.9 million for 2016 (first reconciliation);
- a shortfall of $63.5 million for 2015 (second reconciliation);
- a surplus of $86.3 million for 2014 (third reconciliation);
- a surplus of $92.5 million for 2013 (third reconciliation);
- a surplus of $61.0 million for 2012 (fourth reconciliation);
- a surplus of $30.0 million for 2011 (fifth reconciliation); and
- a surplus of $0.7 million for 2010 (fifth reconciliation).

Methodology, Allocation and Settlement of Deferral Account Balances

The AUC approved the AESO's methodology, allocation, and settlement of the deferral account balances.

No market participant objected to the use of a December 31, 2017 cut-off date in the application, nor to the methodology the AESO used to allocate the voltage control deferral account balance. The AUC accepted the AESO's method to allocate voltage control charges and found the use of a December 31, 2017 cut-off date to be reasonable. The AUC found this would minimize the refunds and subsequent collections (or vice-versa) from market participants that would have occurred if a December 31, 2016 cut-off date was used.

The deferral account reconciliation only applied to Rate Demand Transmission Service ("DTS") and Rate Fort Nelson Demand Transmission Service ("FTS"). The deferral account balances were allocated to individual market participants based on each market participant's percentage of base rate revenue collected, based on Rate DTS and Rate FTS that were in place during the period, by month and by rate component.

Cost Variances

The AUC agreed that a deferral account reconciliation proceeding was the proper venue to consider the prudence of AESO costs incurred with respect to 2016 and any cost variance amounts not already considered in previous deferral account reconciliation decisions related to prior years.

The provisions of the *EUA* and the *Transmission Regulation* provide guidance to the AUC regarding the extent to which it may assess the costs and expenses incurred by the AESO in its tariff (namely, the AESO's own administrative costs, ancillary services costs, and costs related to transmission wires payable under a Transmission Facility Owner's ("TFO") tariff).

The AESO's administrative costs were accepted as filed.

The AUC accepted the AESO's ancillary amounts as filed and the AESO board approved the costs for ancillary services. Section 3(1) of the *Transmission Regulation* requires the AESO to consult with market participants directly affected by these costs. No party indicated that the AESO failed to consult properly.

Summary

The AUC approved the deferral account balances and the net deferral account surplus amount of $26.2 million.

The AUC accepted the accuracy of the deferral account amounts and the calculation of the net deferral account surplus of $26.2 million and noted that no market participant objected to the application.

Alberta Electric System Operator 2019 Balancing Pool Consumer Allocation Rider F (AUC Decision 24037-D01-2018)

Demand Transmission Service - Demand Opportunity Service

In this decision, the AUC considered the Alberta Electric System Operator ("AESO")'s application pursuant to section 82 of the *Electric Utilities Act* ("*EUA*") requesting approval of a $2.90 per megawatt hour ("/MWh") charge to all Demand Transmission Service ("Rate DTS") and demand opportunity service ("Rate DOS") market participants, with the exception of Medicine Hat and BC Hydro at Fort Nelson, for metered energy from January 1, 2019 through December 31, 2019 inclusive ("Rider F").

The AUC approved the applied-for 2019 Balancing Pool Consumer Allocation Rider F without modification, finding that all substantive aspects of the applied-for Rider F were unchanged from the 2018 Rider F.

Legislative Scheme

The Balancing Pool is the agency responsible for managing the power purchase arrangements for several major power plants and was established to facilitate the management of certain assets, revenues, and expenses arising from the transition to competition in Alberta's electric industry.

Section 82 of the *EUA* requires the Balancing Pool to prepare a budget for each fiscal year setting out the estimated revenues and expenses of the Balancing Pool. Based on this forecast, the Balancing Pool determines an annualized amount that will be refunded to (or collected from) electricity market participants over the year.

Under section 82(4) of the *EUA*, the Balancing Pool must notify the AESO of an annualized amount for each fiscal year.

Pursuant to section 82(6)(b) of the *EUA*, the AUC must "approve, with or without modification, the allocation of the annualized amount to the owners of electric distribution systems, industrial systems and persons that have made arrangements under section 101(2)," being Rate DTS and Rate DOS market participants.

Background

The Balancing Pool provided notice to the AESO of a negative annualized amount of $181,319,600 for 2019 and stated that the Balancing Pool's board of directors approved a charge of $2.90/MWh of consumption.

The AESO proposed to charge the annualized amount through a $2.90/MWh charge to all system access services under Rate DTS and Rate DOS through Rider F.

AUC Findings

Section 82(6)(a) of the *EUA* directs the AUC to approve the annualized amount provided to the AESO by the Balancing Pool, without modification. Accordingly, the AUC approved the 2019 annualized amount of negative $181,319,600 provided to the AESO by the Balancing Pool.

The AUC found that the $2.90/MWh to be charged to all Rate DTS and Rate, to recover the annualized amount of negative $181,319,600, was reasonable. With the exception of customers directly connected to the transmission system, the AESO's Rider F flows to end-user electricity customers in the province by means of related Balancing Pool riders implemented by the distribution utilities.

The AUC agreed with the AESO's proposal that all substantive aspects of Rider F, including applicability criteria and use of a $/MWh approach, continued unchanged from the 2018 Rider F, which was previously approved by the AUC and currently in effect.

Summary

The AUC approved the applied-for 2019 Balancing Pool Consumer Allocation Rider F without modification, finding that all substantive aspects of the applied-for Rider F were unchanged from the 2018 Rider F.

AltaLink Management Ltd. AltaLink L.P. Transfer of Specific Transmission Assets to PiikaniLink L.P. and KainaiLink L.P. and the Associated 2017-2018 General Tariff Applications (AUC Decision 22612-D01-2018)

Transmission Assets - Transfer

In this decision, the AUC approved, with conditions, the application of AltaLink Management Ltd. ("AltaLink") requesting approval of the following:

(a) the transfer of specific transmission assets to PiikaniLink Limited Partnership ("PLP") and KainaiLink Limited Partnership ("KLP"); and

(b) the general tariffs for each of PLP and KLP on an interim basis.

The AUC approved the transfer of the assets to PLP and KLP. Applying the no-harm test, the AUC found that the identified financial harm from the transaction could be mitigated through the imposition of conditions. The AUC approved the PLP and KLP general tariffs on an interim basis, effective the date of completion of the transfers.

Background

AltaLink, in its capacity as general partner of AltaLink L.P. and as general partner of each of PLP and KLP filed transfer applications seeking approval for the transfer and sale of a portion of AltaLink's transmission assets pertaining to its 240 kV transmission line between the Goose Lake Substation and the North Lethbridge Substation (the "SW Line"). The portions of the SW Line that were proposed to be sold and transferred were the assets located on the Piikani Reserve No. 147 and on the Blood Reserve No. 148. These transmission assets were referred to as the PLP transmission assets and the KLP transmission assets, respectively.

No-Harm Test for Transfer Applications

In fulfilling its public interest mandate when considering applications pursuant to sections 101 and 102 of the *Public Utilities Act* ("*PUA*"), the AUC applies a no-harm test.

In this case, the AUC considered the following factors associated with the proposed transfers to assess whether they resulted in financial harm to ratepayers:

- incremental audit fees and hearing costs for PLP and KLP Transmission Facility Owners ("TFOs");
- financing arrangements to provide funding to acquire the transmission facilities from AltaLink L.P.;
- financial viability of PLP and KLP; and
- income tax considerations.

Financial Impact

The AUC found that:

(a) approval of the asset transfers, as proposed, would result in ongoing incremental costs to ratepayers for audit fees and hearing costs, approximated for 2017 at $120,000 per year ($35,000 for annual audit fees payable to external auditors, and $25,000 associated with hearing costs, for each of PLP and KLP); and

(b) the repayment terms in the loan agreements resulted in financial harm to ratepayers that, on balance, would leave them worse off than they otherwise would be.

The AUC also determined that the offsetting benefits claimed by AltaLink did not mitigate the financial harm.

However, the AUC found that the identified financial harm from the transaction could be mitigated through the imposition of conditions. The AUC approved the proposed transfers subject to the condition that any unreasonable or undue financial risk to ratepayers arising from the repayment terms in the financing of the proposed transfers would not be included within the AltaLink tariff.

Financing Arrangements

The AUC noted that AltaLink L.P. proposed to finance the sale of a portion of its own assets to enable PLP and KLP to purchase the assets being transferred. As such, the AUC considered the following factors in assessing potential harm to ratepayers:

(a) the reasonableness of the proposed interest rates in the loan agreements;

(b) the choice of lender; and

(c) the reasonableness of the repayment terms in the loan agreements.

The AUC found that the proposed interest rates did not result in increased costs to ratepayers. The AUC also accepted the explanation that because any advances under the loan agreements would bear interest at AltaLink L.P.'s approved weighted average cost of debt, which was the same rate that would be used if the assets remained in AltaLink L.P.'s rate base, ratepayers would be kept whole. The AUC found that ratepayers, on balance, would be no worse off than they were prior to the proposed transfers.

The AUC was not persuaded that, for the purposes of the transfer applications, AltaLink L.P. should be financing the purchase and ongoing financial obligations of PLP and KLP under the terms and conditions of repayment currently reflected in the loan agreements.

The AUC found that the repayment terms as set out in the loan agreements resulted in harm to ratepayers that, on balance, would leave ratepayers worse off than they otherwise would be. Although AltaLink considered the risk of PLP and/or KLP failing to repay the principal and interest to be low, it remained a fact that it was ratepayers, not AltaLink L.P., that were exposed to this risk. Consequently, the AUC approved the proposed transfers subject to the following condition:

- any unreasonable or undue financial risk to ratepayers arising from the repayment terms in the financing of the proposed transfers may not be included within the AltaLink tariff.

Financial Viability of PLP and KLP

The AUC found that ratepayers would not be harmed by the untested financial profile of the new TFOs, namely, PLP and KLP. The terms of the limited partnership agreements provided that any failure on the part of PLP or KLP to contribute capital would be funded by AltaLink L.P. and the deemed equity and debt components of the capital structures would remain the same post-transfer.

Income Taxes

The stand-alone principle provides that only the costs, risks, and returns associated with delivery of regulated utility services should be included in revenue requirement. The AUC relied on the stand-alone principle to assess whether the proposed transfers were likely to harm ratepayers. As such, the AUC declined to consider the ultimate locus of ownership of PLP and KLP when applying the no-harm test regarding potential income tax effects.

The AUC found it reasonable to include a tax provision in the revenue requirements of the new entities. More generally, having found taxable corporate structures such as those proposed in the transfer applications to be a reasonable means of facilitating the ownership, management and operation of the transferred assets, the AUC also found that such taxable corporate structures would leave ratepayers no worse off after the proposed asset transfers than they were before, thus satisfying the no-harm test.

Availability of Unclaimed Capital Costs for Capital Cost Allowance Claims

The AUC was satisfied with AltaLink's explanation that because PLP and KLP decided to roll over their respective unclaimed capital costs for the PLP transmission assets and the KLP transmission assets, there was no risk of harm to ratepayers as a result of a reduction in unclaimed capital costs available for capital cost allowance claims.

The AUC found that the proposed transfers would not result in harm to ratepayers on this basis.

Continuity of Safe and Reliable Service

The AUC found that:

(a) the proposed transfers would not harm ratepayers from the perspective of safety, reliability or the operation of the SW Line post-transfer;

(b) AltaLink demonstrated a track record as a safe and reliable operator of transmission assets since 2001; and

(c) the fact that AltaLink would continue to operate the PLP and KLP transmission assets post-transfer were factors satisfying the AUC that no harm would result to rate.

Control and Governance Matters: Ring-Fencing and Inter-Affiliate Code of Conduct

Ring-fencing measures are designed to isolate the creditworthiness of the operating subsidiary from that of its parent entity. The underlying purpose of ring-fencing measures is to shelter the utility and its customers from any negative ramifications arising from the activities of affiliated entities.

The AUC found no harm in relation to the proposed ring-fencing measures. The AUC accepted AltaLink's submission that because PLP and KLP would receive debt financing directly from AltaLink L.P., establishing credit ratings for PLP and KLP to raise their own public debt financing under the proposed transfers were not a concern. The AUC was satisfied that the proposed ownership structure would allow PLP and KLP to benefit from the same ring-fencing measures already in place. The AUC was also satisfied with the other measures proposed by AltaLink to ensure the financial viability of PLP and KLP. These included restricting the businesses of PLP and KLP under the limited partnership agreements to regulated transmission on their respective reserves, thereby restricting the risks of PLP and KLP to those associated with regulated transmission assets.

The AUC accepted AltaLink's submission that any inter-affiliate arrangements for products or services entered into by PLP and KLP would be subject to AltaLink's Inter-Affiliate Code of Conduct and remain subject to the AUC's broad regulatory oversight. Therefore, the AUC found that this aspect of the proposed transfers satisfied the no-harm test.

<u>PLP and KLP General Tariff Applications</u>

AltaLink requested the approval of revenue requirement allowances for PLP and KLP in the amounts of $5,218,500 and $3,482,400 for the year 2017 and $5,105,300 and $3,408,200 for the year 2018, respectively.

The AUC accepted AltaLink's proposed pro-rata mechanism to implement the PLP and KLP tariffs and adjust the revenue requirement in AltaLink's general tariff application. However, because the 2018 revenue requirements of the PLP and KLP tariffs were approved only on an interim basis, AltaLink, in its capacity as the general partner of AltaLink L.P., was not required to adjust its revenue requirement in the same prorated manner immediately.

Rate Base

The AUC directed that the effective date for the evaluation of the assets be the effective date of the asset transfers to PLP and KLP. Further, the AUC waived the application of the half-year rule in the initial year of operations for PLP and KLP to enable this adjustment. The AUC found that waiving this rule would not harm ratepayers.

Because both PLP and KLP would be new TFOs, neither would have any transaction history to perform their own lead-lag study for determining working capital and revenue requirement. In this circumstance, the AUC found that the methodology and calculations used to support necessary working capital amounts for the PLP and KLP tariffs were reasonable. Accordingly, the amounts of $490,400 and $327,300 may be used as the basis for the necessary working capital allowance within the interim tariffs for PLP and KLP, respectively.

Direct Operation and Maintenance Costs

The AUC approved AltaLink's forecasts of direct operation and maintenance ("O&M") costs for PLP and KLP for the years 2017 and 2018 in the amounts of $301,500 and $183,300. The AUC approved these amounts to be used as the basis for revenue requirement allowances for direct O&M costs in the interim tariffs for PLP and KLP, respectively.

The AUC found the direct O&M costs were reasonable because they would be offset on a one-to-one basis by a revenue offset applied to AltaLink L.P.'s tariff.

Payments in Lieu of Property Tax

The AUC approved AltaLink's forecasts of the cost of payments in lieu of taxes for PLP and KLP for the years 2017 and 2018 as filed. The AUC approved AltaLink using the amounts of $214,900 and $65,900 as the basis for revenue requirement allowances for the cost of payments in lieu of taxes in the interim tariffs for PLP and KLP, respectively.

The AUC was not persuaded that the costs associated with payments in lieu of taxes would grow at the same rate following the transfer of assets to PLP and KLP as they would have if the transfers had not taken place. Accordingly, the AUC determined that additional oversight of payments in lieu of taxes would be required, at least initially, as part of the AUC's oversight of a proposed deferral account and in respect of future PLP and KLP tariffs.

General and Administrative Expense

The AUC approved the general and administrative expense forecasts of $156,500 for 2017 and $160,900 for 2018 within the interim tariffs for each of PLP and KLP.

All costs incurred by AltaLink for general and administrative expenses would be charged through a fixed fee inter-affiliate charge from AltaLink L.P. to each of PLP and KLP.

The activities within the general and administrative expense charges to PLP and KLP included accounting, treasury, audit, legal and regulatory.

Because all general and administrative expenses included in the PLP and KLP revenue requirements, other than audit costs and hearing costs, would be offset on a one-to-one basis by a revenue offset applied to AltaLink's tariff, the AUC found these costs were reasonable.

The AUC was satisfied that the method employed to arrive at the forecast for general and administrative expenses in the PLP and KLP tariffs were reasonable.

However, the AUC did not consider that ratepayers should bear any incremental audit costs resulting from the proposed transfers. Accordingly, as audit costs were included within the general and administrative expense forecasts of PLP and KLP, the AUC found that the audit costs of $35,000 should be removed from the U.S. Account 920 forecasts of both PLP and KLP.

Depreciation Expense

The AUC approved AltaLink's depreciation expense forecasts of $1,482,500 for each of 2017 and 2018 for PLP, and $871,300 for each of 2017 and 2018 for KLP, as filed.

Return on Rate Base

The AUC approved the proposed revenue requirement allowances for return in the amounts of $3,011,800 and $2,910,600 for the years 2017 and 2018, respectively, for PLP, and $2,153,600 and $2,091,800 for the years 2017 and 2018, respectively, for KLP, as filed.

The AUC agreed with AltaLink's proposal that the same capital structure and rates of return be applied to AltaLink L.P., PLP, and KLP.

Income Tax Expense

The AUC approved the use of a zero income tax expense within the interim PLP and KLP tariff to commence the effective date of the transfers.

The AUC considered the use of the flow-through method for the calculation of income tax expense within the applied-for PLP and KLP tariffs was reasonable for AltaLink's tariff.

Deferral Account Reserve Accounts

Regarding each of the requested deferral accounts, the AUC:

- approved a self-insurance reserve ("SIR") account;
- denied a hearing cost reserve account;
- deferred consideration of a deferral account for payments in lieu of property taxes;
- deferred consideration of a deferral account for annual structure payments; and
- approved a direct assign capital deferral account.

The AUC agreed with AltaLink's rationale that because the commercial insurance costs for transmission assets was prohibitively high, it was reasonable for PLP and KLP to have a SIR account structured on the same basis as the SIR account approved for AltaLink L.P.

Summary

The AUC approved the transfer of the assets to PLP and KLP. Applying the no-harm test, the AUC found that the identified financial harm from the transaction could be mitigated through the imposition of conditions. The AUC approved the PLP and KLP general tariffs on an interim basis, effective the date of completion of the transfers.

Blazer Water Systems Ltd. 2019-2020 General Rate Application (AUC Decision 22319-D01-2018)

Water Utilities - General Rate Application - Interim Basis

In this decision, the AUC approved the continuation of Blazer Water Systems' ("Blazer") existing rates as interim rates beginning January 1, 2019.

The AUC ordered Blazer to file a compliance filing by February 22, 2019.

Background

The water facilities were originally built in the late 1980s to service Bearspaw Meadows. In 1999, the ownership of Blazer changed from the original developer to the golf course developers, who expanded and improved the water treatment plant.

Blazer's water system consisted of several previously separate and distinct water systems that were combined into a single water system, which is currently owned and operated by Blazer. This amalgamation of the water systems began in 2013.

As a condition of Rocky View County's approval of the first phase (now completed) of the Watermark development, Blazer was also required to offer water utility services to the Bearspaw Village ("BPV") and Blueridge Rise ("BRR") communities. To meet the water needs of BPV, BRR, and the Watermark development, it was necessary to expand Blazer's water treatment plant and treated water storage facilities to increase capacity.

In 2013, Blazer's production capacity was able to serve approximately 250 homes. Blazer's expansion and upgrade project was completed in December 2014, and its system capacity can now serve approximately 1,250 homes.

Blazer's water system consists of river intake pumps in the Bow River, a raw water pumping station and raw water transmission main, which supply raw water to the irrigation pump house and water treatment plant. The irrigation pump station supplies untreated water through the irrigation water distribution systems to the residential irrigation customers in Lynx Ridge. The water treatment plant and treated water storage supply potable water through the transmission mains and potable water distribution systems to Blazer's potable water customers.

Blazer processes potable water through a water treatment facility and provides water delivery to customers. Water service is directly provided using Blazer's distribution system to residential customers in Blazer's franchise area. Blazer also provided irrigation water service to a subset of customers in Lynx Ridge.

Jurisdiction

The *Public Utilities Act* ("*PUA*") applies to public utilities that the AUC regulates, including water utilities.

Section 1 of the *PUA* defines "owner of a public utility" and a "public utility". The AUC was satisfied that Blazer met the definitions of a "public utility" and an "owner of a public utility" as defined in the *PUA*. Blazer operates "a system, works, plant, equipment or service" for the delivery or furnishing of water directly or indirectly to customers."

Section 78 of the *PUA* gives the AUC the jurisdiction and power to deal with public utilities and the owners of public utilities. The AUC must ensure that it sets just and reasonable rates for the utility services while balancing the interests of both the customers and the utility.

Proposed Revenue Requirements

Blazer's forecasted revenue requirements for the 2019 to 2020 test period were $1,056,289 for 2019 and $1,062,304 for 2020.

Blazer also requested approval of a revenue deficiency deferral account and terms and conditions of service.

Bearspaw Village and Blueridge Rise Water Cooperatives

The BPV and BRR agreements each contained a section regarding the monthly contingency fund assessment that would be added to the bills of the BPV and BRR customers. Blazer requested that these sections be revised to provide a monthly contingency fund amount of $30/customer/month.

The AUC considered that it was premature to consider Blazer's request for approval of sections of the BPV and BRR agreements. The AUC found that there was insufficient evidence on the record with respect to calculation of the $30 contingency fund amount.

Accordingly, the AUC directed Blazer to provide in the compliance filing to this decision the calculation of the $30 contingency fund amount and an explanation on why this amount should be approved.

Phase I - Revenue Requirement

The test period revenue requirement included operating and maintenance ("O&M") costs, depreciation on owner-invested capital, and allowed return on owner-invested capital.

O&M and Administration Costs

O&M and administration costs were either designated by Blazer as varying with flow rate or not varying with flow rate. Those costs that vary with flow rate were forecast to increase proportionally to the expected increase in water treatment plant production of 6.3-6.4 percent and inflation of 1.8 percent. Those that do not vary with flow rate were forecast to increase at the inflation rate only.

The AUC approved the allocated costs for the administrative staff position and office rent as filed by Blazer.

The AUC directed Blazer to update its financial model, in its compliance filing, to reflect an allocation of 80 percent of the general manager's salary to Blazer's revenue requirement. The AUC found the reasonable amount to allocate to the regulated utility was the annual salary for the staff person multiplied by the proportion of time spent by that staff person working for the regulated utility. In the case of Blazer's general manager, this meant that the allocation of the general manager's salary should be set at 80 percent of the general manager's annual salary.

For the purposes of this application, the AUC was generally satisfied that the hourly rates for the operators supplied by H2o Pro were generally competitive with rates in other contracts approved by the AUC.

The AUC further accepted Blazer's explanation that, due to the expansion of the water treatment plant and adherence to the operator requirements of Alberta Environment, the increased hours and rates in 2016 were necessary to provide safe and adequate water service. Given that Blazer paid the operator rates since 2016 while operating at a revenue shortfall, a reduction in Blazer's forecast costs for the operating contract was not warranted.

However, the AUC agreed with BPV with respect to the absence of an explanation regarding the splitting of O&M costs on the H2o Pro invoices into two cost codes. Blazer did not explain what these individual cost codes reflected regarding the service provided by H2o Pro in a given month.

The AUC directed Blazer to explain the difference between the two different cost codes on the H2o Pro invoices, why the charges are split on the invoices, how the two amounts appearing on the invoices were derived and any potential consequences of not splitting the amounts, as part of its compliance filing.

Savings Due to Lynx Ridge Treated as a Single Customer

The AUC found that it would not direct a reduction to Blazer's revenue requirement for reduced billing costs as a result of the transition of Lynx Ridge irrigation services to a single customer bill. Given that each Lynx Ridge customer would still receive individual potable water bills, the AUC considered that any actual reduction in O&M and administration costs associated with transitioning Lynx Ridge to a single residential irrigation customer would likely be immaterial.

The AUC agreed with Blazer's submission that its billable costs did not actually decrease by $56,194 per year as a result of treating all Lynx Ridge residential irrigation customers as a single customer but rather that this was simply an allocation of the revenue requirement to fewer customers. However, the AUC found that the fact that the revenue requirement allocated to residential irrigation decreased by $56,194 without an actual decrease in Blazer's costs indicated that the customer base allocator for Blazer's costs was not the best allocator for its O&M and administration costs.

The AUC found that all O&M and administration costs proposed to be allocated based on the number of customers should be allocated based on volume.

Rate Base

The AUC directed Blazer to update Schedule 12 of the financial model to reflect the actual net book value as of December 31, 2018, in its compliance filing to this decision. As part of this direction, the updated net book value must take into account any findings and determinations of the AUC in the other sections of this decision.

The AUC considered that it was necessary to update the opening rate base numbers to reflect the significant amount of time that passed since Blazer filed its initial application with the AUC.

Forecast Capital Additions

The AUC accepted that Blazer attempted to recover the previous infiltration gallery in order to continue service to customers and approved Blazer's decision for replacement of these systems. Given the expansion of Blazer's water treatment plant and its forecasted customer base growth, the AUC considered that replacement of the infiltration gallery was necessary for the continued safe and reliable operation of Blazer's water utility. The AUC agreed with Blazer that continued use of the submersible pumps would require provincial and federal approvals, and would lead to increased maintenance costs.

However, the AUC considered that Blazer's proposed capital costs for the river intake replacement should be updated to reflect the time that passed since Blazer filed its application to the AUC in January 2017.

Accordingly, the AUC directed Blazer to file updated actuals for costs associated with the river intake replacement, the costs incurred to date for the replacement, and to update its forecast for any remaining costs for this project in the compliance filing.

The AUC found that a contingency allowance amount for possible unexpected works was not a regulatory cost that related to a tangible capital asset, i.e., it was an amount that was unrelated to an asset that was required for regulatory service. An asset is only included in rate base when it is operational. For these reasons, the AUC directed Blazer to exclude any capital additions or asset amounts for "contingency allowance against unexpected works" in the compliance filing,

Depreciation

The AUC approved the depreciation rates proposed by Blazer and found them acceptable for depreciating its capital assets because they were based on the lives of the capital assets, which is an underlying principle of depreciation.

The AUC directed Blazer to adopt the straight-line basis of calculating depreciation for 2019 and 2020 in the compliance filing to this decision.

<u>Return on Debt and Equity and Capital Structure</u>

The AUC found that the applied-for return on equity ("ROE") percentages were in accordance with the ROEs approved in the 2016 generic cost of capital decision, and the 2018 generic cost of capital decision. Blazer used an ROE of 8.30 per cent for 2015 and 2016 and increased this to 8.50 percent for 2017 and subsequent years.

The AUC found that a deemed capital structure of 60 percent debt and 40 percent equity for Blazer for 2019 and 2020 was warranted given the size of Blazer's operations and its business risk.

<u>Blazer Subsidy, Revenue Deficiency Deferral Account and Connection Fee</u>

Blazer proposed to address the overbuilt nature of its water system by foregoing a percentage of its allowed return on owner-invested capital, and by determining that percentage in a manner that arrived at rates, which Blazer submitted were within the range of rates charged by other water utilities in the area surrounding the city of Calgary.

The AUC found it unreasonable to calculate the Blazer subsidy by selecting a percentage of allowed foregone return in order to arrive at a specified variable rate charged to customers.

The AUC directed Blazer to update its financial model such that the subsidy was calculated based on foregoing a percentage of Blazer's depreciation and return, and whereby that percentage was calculated by dividing the forecast number of homes for the year by 1,250 (the number of homes the water treatment plant can currently serve). This update is to be included in the compliance filing.

The AUC found that it was also reasonable for Blazer to collect a connection fee to offset some of that revenue deficiency as future water customers were added to the system.

Although the AUC approved Blazer's proposed connection fee, the AUC found that a deferral account was not warranted because it had approved a set fixed connection fee for recovery in the test years that provided certainty in recovery of connection fee amounts for Blazer.

<u>Phase II - Allocation and Rate Design</u>

Rate Classes

Blazer requested approval of rates for four customer classes:

(a) the WPO customer class (potable water customers other than BPV/BRR customers);

(b) the BPV/BRR customer class;

(c) the residential irrigation customers class (Lynx Ridge); and

(d) commercial irrigation (the Lynx Ridge Golf Course).

The AUC approved Blazer's request for two potable water rate classes and two irrigation rate classes.

Cost Allocators

The AUC approved Blazer's allocations for all capital costs that did not use the time-of-use allocator. The AUC was satisfied that, apart from the time-of-use allocator, all other capital cost allocators reflected the underlying drivers of the costs and found that the resulting allocations of capital costs were reasonable.

The AUC denied Blazer's use of an allocator based on a function of water consumption and time-of-use for the following O&M cost categories:

(a) materials supplied and maintenance at the raw water pump station; and

(b) the electricity - river pump house.

The AUC accepted these costs varied with flow rate to some degree. The AUC, therefore, directed Blazer to use water consumption as the sole allocator for these two cost categories.

Consumption Data

The AUC found that Blazer should use the average water consumption for the BPV/BRR potable water rate class that was available to Blazer. The AUC directed Blazer to design the potable water rates for the two potable water rate classes using average water consumption data specific to those rate classes. The AUC further directed that the average water consumption data should use the actuals for 2016.

Tiered Water Consumption Rates

The AUC approved the use of 60 m^3 as the threshold for the block rate structure.

The AUC considered that the threshold of 60 m^3 was not overly restrictive. The AUC found that this determination to approve a block rate structure was not unreasonable given that in 2015 and 2016 only six percent of Blazers' customers consumed over 60 m^3 of water per month.

The AUC considered that Blazer's proposed block rate structure should act as an incentive to customers to monitor their monthly potable water use. If water use was reduced because customers were aware of the increased rate for monthly consumption above 60 m^3, this will also help reduce those O&M expenses that vary with flow rate to the benefit of the utility and customers.

Summary

The AUC approved the continuation of Blazer's current rates on an interim refundable basis, as of January 1, 2019. The difference between the interim and final rates approved will either be collected from customers or refunded to customers.

The AUC found that approval of Blazer's costs and allocations in this decision resulted in just and reasonable cost allocation to the commercial irrigation rate class and other irrigation customers.

The AUC directed Blazer to submit its compliance filing to this decision by February 22, 2019.

AUC Announcement: New General Phone Number and Email Address Provide Onestop Access to the AUC (November 29, 2018)

Toll-Free Phone Number - New Email Address

The AUC announced the implementation of a new toll-free phone number which will replace the former consumer relations phone number and the information services numbers.

The AUC also announced it will stop using the consumer relations email address. The former phone number and email address will be discontinued in June 2019.

Contact the AUC toll-free at:

310-4AUC (inside Alberta)
1-833-511-4AUC (outside Alberta)
info@auc.ab.ca

NATIONAL ENERGY BOARD

Manitoba Hydro Application for the Manitoba-Minnesota Transmission Project (NEB Decision EH-001-2017)

International Electricity Transmission Line - Constitution Act, 1867 - Section 92A

In this decision, the NEB considered an application by Manitoba Hydro for a permit pursuant to section 58.11 of the *National Energy Board Act* ("*NEB Act*") to construct and operate the Manitoba-Minnesota Transmission Project ("the Project"). The Project included a 500 kV international power line ("IPL") from the Dorsey Converter Station near Rosser, Manitoba to the border of the U.S.; and related changes to other IPLs.

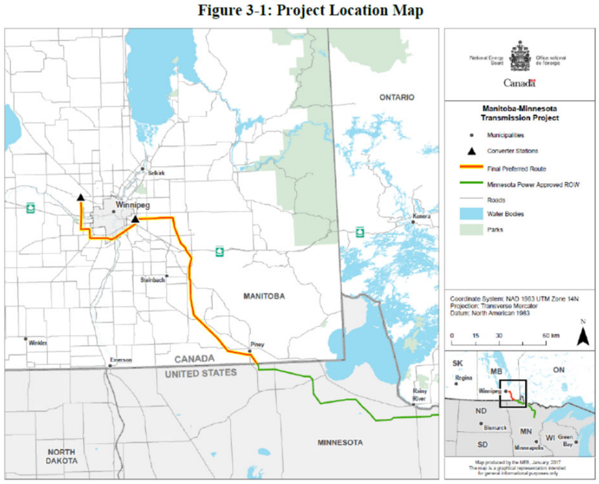
The NEB found that the Project was and would be required by the present and future public convenience and necessity. The NEB, therefore, recommended that the Governor in Council ("GiC") approve the NEB's issuance of a certificate pursuant to section 58.16 of the *NEB Act*.

Project Overview

The figure below shows the location of the Project.

Figure: Project Overview Map

Figure 3-1: Project Location Map



Jurisdictional Context

The NEB explained that:

- Prior to the 1982 amendments to the *Constitution Act, 1867*, regulation of interprovincial and international marketing was under the exclusive jurisdiction of the Parliament of Canada under its trade and commerce power in subsection 91(2) of the *Constitution Act, 1867*.

- As a result of the 1982 amendments and the addition of section 92A to the *Constitution Act, 1867*, provinces have concurrent legislative powers in relation to the export of electricity production to other parts of Canada - but notably not in relation to the export of electricity production from Canada.

- Section 92A created overlapping jurisdiction that reflected the complex competing interests of federal and provincial governments in resource development and management in Canada.

- The *NEB Act* was amended in 1990 to accommodate the overlapping jurisdiction it now shared with the provinces. Those amendments were an attempt to respect, to the extent possible, provincial sovereignty but preserve the federal government's effective jurisdiction over the international export of natural resources.

- Portions of IPLs can, for example, be subject to provincial law to the extent that the power line is "within that province" under section 58.2 of the *NEB Act*.

- The physical point on a power line where NEB jurisdiction over IPLs begins, as opposed to that considered to be "within that province," is not defined in the *NEB Act*. A general rule of practice evolved over the years where the NEB assumed jurisdiction over IPLs from the last substation before an international border crossing.

- In many cases, this approach limited the geographic jurisdiction of the NEB to a few kilometres or, on some occasions, to a few metres. The practice continued for decades, and there had been no challenge from provinces or proponents as to the reasonableness of the approach.

Facilities, Safety, and Emergency Response Matters

The NEB found that the overall design of the proposed Project used sound engineering practices in respect of layout, tower design, and line and equipment selection.

The purpose of the Project was to increase import and export transfer capability limits across the Manitoba to U.S. interface ("MHEX"), the Manitoba Hydro transmission system interconnection to the U.S. transmission system through four IPLs. The Project included construction of the new Dorsey IPL (the "Dorsey IPL") and alterations to each of the existing Glenboro IPL and Riel IPL.

The NEB noted that the existing long-term power transfer capability of the MHEX, including a 75 MW reliability margin, was 2175 MW (summer and winter) for exports and 775 MW (summer and winter) for imports. With the proposed Dorsey IPL in place, the export power transfer capability was expected to increase by 883 MW to 3058 MW, and the import transfer capability was is expected to increase by 698 MW to 1473 MW. Manitoba Hydro stated that the import transfer capability increase beyond 1473 MW was limited by a constraint in the connecting U.S. system.

Regarding the power transfer capability and impacts to connected bulk systems, the NEB found that the Project's import transfer capability beyond 1473 MW could only be achieved upon mitigation of a constraint in the U.S.. To ensure that operations in the U.S. would not impose unacceptable operating conditions on the neighbouring Canadian transmission systems, the NEB imposed, as condition of approval, limits on import and export of power, and required Manitoba Hydro to file confirmation from the provincial system operators (Manitoba and Saskatchewan) that the reviewed operating scenarios would not impose unacceptable operating conditions on their electric systems.

Economic and Financial Matters

To determine if there was an economic need for the Project, the NEB assessed the likelihood that Project would be used at a reasonable level over its economic life and would contribute to Canadians benefiting from efficient energy infrastructure. The NEB considered information relating to the supply, demand and load conditions of the markets the Project would service, as well as other benefits of the proposed Project. The NEB also considered the financial viability of the Project.

The NEB found that:

(a) there was an economic need for the Project;

(b) there was adequate supply, markets, and contracts such that it was reasonable to expect the Project to be used and useful over its economic life;

(c) the use of the line for both exports and imports would financially benefit Manitoba Hydro and Manitoba ratepayers; and

(d) the Project would improve the reliability of the integrated system, and Manitoba ratepayers would benefit from the reliable provision of electricity.

Public Consultation

The NEB explained that applicants are expected to undertake an appropriate level of public involvement, commensurate with the setting, nature, and magnitude of a project.

The NEB acknowledged Manitoba Hydro's efforts to identify and consult with potentially affected and interested stakeholders and its commitment to continuing to consult throughout the lifecycle of the Project. The NEB found that the overall design and implementation of Manitoba Hydro's public consultation program was appropriate for the scope and scale of the Project. The NEB noted that Manitoba Hydro had been consulting on the Project since 2013 and had committed to continuing consultation during all phases of the Project.

Indigenous Matters

The NEB found that approval of the Project was consistent with section 35 of the *Constitution Act, 1982* and the honour of the Crown.

In reaching this conclusion, the NEB stated that it had considered:

(a) the information submitted regarding the nature of potentially affected Indigenous interests in the Project area, including information on constitutionally protected Indigenous and Treaty Rights; and

(b) the anticipated effects of the Project on those interests and the concerns expressed by Indigenous communities.

In light of the nature of the interests and the anticipated effects, the NEB evaluated the consultation undertaken, including the mandated engagement performed by Manitoba Hydro and the consultation undertaken through the NEB's project assessment process. The NEB also considered the mitigation measures proposed to address the various concerns and potential effects.

The NEB found that:

(a) there was adequate consultation and accommodation for the purpose of the NEB's decision on this Project;

(b) Manitoba Hydro designed and implemented appropriate and effective engagement activities for the Project, and the NEB process was appropriate for the circumstances;

(c) any potential Project impacts on the interests, including rights, of affected Indigenous communities, after mitigation, were not likely to be significant and could be effectively addressed; and

(d) the Project would benefit local, regional and provincial economies and result in increased employment for Indigenous individuals and contracts for Indigenous-owned businesses.

Environmental and Socio-Economic Matters

The *Canadian Environmental Assessment Act, 2012* (the "*CEAA, 2012*") required the NEB, as a responsible authority, to make a determination of the significance of Project effects. The NEB conducted an environmental assessment of the Project and found that the proposed Project was not likely to cause significant adverse socio-economic or environmental effects as defined within the *CEAA, 2012*.

The NEB found that the Project's potential contributions to cumulative effects in the region had been substantially reduced through Manitoba Hydro's Project design and would be further reduced as a result of the mitigation measures (including adaptive management measures). The NEB found that some of the Project's potential adverse residual effects might interact with effects from other projects and activities over the long-term and in some cases, be permanent. However, the NEB found that most residual effects would be low to moderate in magnitude and restricted to localized areas, and would not likely result in significant adverse cumulative effects.