REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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ALBERTA ENERGY REGULATOR

AER Administration Fees (Industry Levy), AER Bulletin 2019-31

Bulletin - Administrative Fees - Industry Levy

Energy Regulation Program

Due to delays in the finalization of the 2019/20 budget, the Government of Alberta approved the AER to issue two sets of administrative fees for 2019. The first set of administrative fees ($154M) was issued on July 12, 2019, to allow the AER to secure the appropriate funds to operate until a budget was approved. The Government of Alberta approved a total industry levy of $233.2M, and the AER is now issuing the second set of administrative fees to collect the remaining $79.2M.

The amount of each invoice depends on the AER's revenue requirement, 2018 production volumes, the number of wells and schemes, and the number of operators within the sector. Any change in the above factors changes the invoice amount for each operator. Invoices to operators detailing the fee calculations will be mailed on November 29, 2019, and payments are due by January 6, 2020.

The *Responsible Energy Development Act* ("*REDA*") authorizes the AER to make rules to levy an administration fee on the oil and gas, oil sands, and coal sectors, and the imposition of a late-payment penalty, which is set at 20 percent on any portion of the fee that remains unpaid after the due date.

Invoices for administration fees are sent to and are payable by the party that was the operator on record (as defined in section 29 of *REDA*) as of December 31, 2018. For conventional wells and oil sands schemes, "operator" means the entity that files well production, injection, or disposal data, or all three, with Petrinex, Canada's Petroleum Information Network. If the operator fails to pay the fee, the late-payment penalty will be added, and the AER will pursue the approval holder (if the actual operator and approval holder are two different parties) for payment of the full amount.

If the administration fee or penalty is not paid, the AER may use various enforcement tools to collect payment:

(a) the AER may close producing wells or facilities.

(b) the AER may garnish production from operating wells and facilities to collect any outstanding debts. Under section 103 of the *Oil and Gas Conservation Act*, if an approval holder has failed to pay debts to the AER, the AER has a lien on its wells, facilities, and pipelines and on land or interests in land, including mines and minerals, equipment, and petroleum substances. The AER's lien has priority over all other liens, charges, rights of set-off, and mortgages and other security interests; and

(c) the AER may use other enforcement tools, as set out in legislation.

Oil and Gas

The administration fee in the conventional oil and gas sector is based on individual well production of oil/bitumen or gas, and the number of production and service wells for the year ended December 31, 2018.

All operating wells are classified into one of eight base fee classes, as set out in the *Alberta Energy Regulator Administration Fees Rules* ("*AFR*"). In addition, an adjustment factor is specified and applied to each base fee. This adjustment factor ensures that the total administration fee collected for the sector satisfies the revenue requirement for the AER.

Oil Sands

Fees are levied in five categories based on operating information for the 2018 calendar year. An operator may have activities in more than one category. Each category is subject to an adjustment factor.

Coal

The administration fee for coal is based on each mine's share of total production volumes for the year ended December 31, 2018. It is set at $ 0.0.060932 per tonne of coal, as specified in the *AFR*.

Appeals

Payment of all invoices is required by January 6, 2020, regardless of whether an appeal has been filed. Following a decision of the appeal, adjustments will be applied as needed.

Amendments to Manual 013: Compliance and Enforcement Program, AER Bulletin 2019-27

Bulletin - Compliance Assurance

The AER released a new edition of *Manual 013: Compliance and Enforcement Program*. This manual provides details on how the AER administers compliance assurance and guides AER staff in the development and execution of compliance processes and procedures. Since the original release of this manual in February 2016, the AER's compliance assurance program has evolved, requiring amendments to some of the sections. Some grammar and formatting were also amended for clarity.

Major changes include the following:

- section 3 has been expanded to discuss compulsory reporting as one way the AER becomes aware of non-compliances;
- sections 4 and 5 have been merged and simplified;
- the following compliance and enforcement tools in section 6 have been clarified: notice of noncompliance, warning, and administrative sanctions;
- the section on administrative penalties has been expanded to include economic benefit; and
- section 6 now includes information on the compliance dashboard.

Change to Consent Requirements When Crown Mineral and Disposal Rights Overlap, AER Bulletin 2019-30

Bulletin - Disposal Schemes - Overlapping Crown Mineral Rights Holders

On October 31, 2019, Alberta Energy released Information Letter 2019-37. The AER will no longer require proof of consent from overlapping Crown mineral rights holders for new or existing disposal schemes where the disposal scheme applicant or approval holder has a valid Crown authorization to dispose issued by Alberta Energy under section 54(5) or section 32(4) of the *Mines and Minerals Act*.

The AER will revise any affected regulatory instruments to reflect this change.

New Edition of Directive 081, AER Bulletin 2019-26

Bulletin - Water Disposal - In Situ Oil Sands

The AER released a new edition of *Directive 081*: *Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sands Schemes*. It consolidates various aspects of water management requirements for thermal in situ oil sands operations. It sets water disposal limits and includes guidance for reporting facility water streams to Petrinex. The goal is for operators to minimize the use of high-quality non-saline make-up water by recycling produced water efficiently and using alternative water sources where possible. Efficient water treatment, recycling, and disposal at thermal operations will optimize overall water use and energy efficiency.

A draft of the directive was released on June 20, 2019, and public feedback was accepted through July 19, 2019. A summary of the feedback, including AER responses, is available on the directive's webpage.

Pipeline Integrity Management Programs Must Consider Slope Movement, AER Bulletin 2019-28

Bulletin - Pipeline Integrity Management

A number of factors can increase the instability of slopes, including precipitation. The AER has noted a slight increase in the number of pipeline failures in 2019 resulting from earth movement of unstable slopes.

Licensees must consider natural hazards as part of their integrity management programs. The *Pipeline Act* and *Pipeline Rules* require licensees to follow the requirements contained in the *Canadian Standards Association (CSA) Z662-19: Oil and Gas Pipeline Systems*. In particular, clauses 3.1.2, 3.2, and 3.3 require licensees to have a safety and loss management system, manage risks, have integrity management programs that monitor for conditions that can lead to pipeline failure (including slope movement), and act to eliminate or mitigate such conditions. As well, Annex N outlines in more detail activities that must be conducted by all licensees to identify and control hazards through proper risk management of their entire pipeline inventory. Failure to comply with these requirements may be a contravention under the *Pipeline Act* and *Pipeline Rules*.

The AER encourages operators to assess integrity management programs and how they address the risk to pipelines as it relates to natural hazards, including slope movement. Suitable management may require the involvement of specialized skilled expertise in this area. Areas of high concern should be identified, and suitable mitigation measures implemented. Suitable measures could include increased surveillance of rights-of-way, patrols, and inspections of areas subject to slope movement.

The AER encourages operators to:

- Adopt emerging best practices for real-time monitoring of precipitation levels, slope movement, and pipe strains of the locations that are most susceptible to failure from slope movement.
- Monitor events of heavy precipitation and proactively shut-in or purge pipelines if the potential risk is high.
- Improve leak detection strategies and operational monitoring in potentially affected areas to enable rapid detection and response to a leak, should one occur.
- Conduct engineering assessments of pipelines where slope movement has occurred, which may require specialized inspection techniques, to determine if pipelines have suffered damage.
- Relocate existing lines or install structures or cover material to protect the system from external loads.

***Request for Regulatory Appeal by DBS Resources Ltd. & North Shore Resources Ltd.*, Request for Regulatory Appeal No.:1922370 & 1922372**

Request for Regulatory Appeal - Timeframe to File

In this decision, the AER considered DBS Resources Ltd. ("DBS") and North Shore Resources Ltd. ("North Shore")'s requests for regulatory appeal of their respective January 4, 2019 Notices to Pay Abandonment Costs ("Notices") under section 38 of the *Responsible Energy Development Act* ("*REDA*"). The AER dismissed the requests for regulatory appeal of the Notices.

<u>Background</u>

On January 4, 2019, the AER sent North Shore two Notices of Abandonment Costs for wells 02/07-09-040-04W5M and 00/07-09-040-04W5M. The AER also sent a separate Notice of Abandonment Costs to DBS for the above wells. The letters advised the parties that the AER had completed the required work to properly abandon the well sites and informed the two companies that payment was required in full by February 4, 2019.

On February 22, 2019, DBS and North Shore responded to the Notices requesting a reduction of 38 percent of the abandonment costs or a meeting with the AER to discuss their concerns with the abandonment costs or an extension on the time for payment. On March 25, 2019, the AER responded to the February 22, 2019 letter outlining the AER's authority to order a well abandoned, to require working interest partners to pay for this work and extended the deadline to pay from February 4, 2019, to April 30, 2019.

On April 23, 2019, DBS and North Shore filed separate (but identical) requests for regulatory appeal (the "Requests") of the Notices.

<u>Legislative Framework</u>

The applicable provision of *REDA* regarding regulatory appeals states:

> 38(1) An eligible person may request a regulatory appeal of an appealable decision by filing a request for regulatory appeal with the Regulator in accordance with the rules.

Subsection 36(a) of *REDA* defines an "appealable decision." For the present purposes, the AER noted that the relevant definition was contained in subsection 36(a)(iv), which states that an appealable decision includes:

> A decision of the Regulator that was made under an energy resource enactment, if that decision was made without a hearing.

<u>Reasons for Decision</u>

DBS and North Shore argued that the March 25, 2019 letter contained many "appealable decisions."

The AER found that the only decision contained in the March 25, 2019 letter, was to extend the time provided to DBS and North Shore to pay their portion of the costs. This was a separate decision from that contained in the January 4, 2019 Notices. While the decision to extend the time to pay was an appealable decision, it was not the subject of this request for regulatory appeal as there was nothing in the grounds for regulatory appeal or the reply materials to suggest that DBS and North Shore were challenging the extension of time that was granted. Accordingly, the AER found the January 4, 2019 Notices were appealable decisions and the subject matter of the Requests.

The AER noted that section 30(3) of the *AER Rules of Practice* ("*Rules"*) requires that a request for a regulatory appeal be made within the specified timeframes after the making of the decision for which an appeal is sought. The decision regarding the abandonment costs was made under section 30(2) of the *Oil and Gas Conservation Act*. Arguably, this cost allocation was an order, and therefore the seven-day timeframe in section 30(3)(j) of the *Rules* would apply. However, the AER found that even if the applicable timeframe for filing a request for regulatory appeal was the 30 days provided for in section 30(3)(m) of the *Rules*, then the Requests were out of time as they were made well after that period.

The AER found that, as the Requests were made outside of the timeframes specified in the *Rules,* the Requests were not filed in accordance with the *Rules*. The AER dismissed the Requests pursuant to section 39(4)(c) of the *REDA*.

***Tracking and Manifesting Produced Water*, AER Bulletin 2019-29**

Bulletin - Waste Management - Produced Water

On November 19, 2018, Alberta Transportation issued Permit 2018-4703 for transporting produced water by truck that has not been cleaned or purged. Due to the overlap with the AER's tracking and manifesting requirements found in *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry*, some confusion has arisen.

All *Directive 058* requirements are still in force and are independent of Alberta Transportation requirements. Companies must continue to comply with all AER requirements, including the following:

- track, report, and manifest produced water using the code "WATER: Water – Produced (including brine solutions)," even if being transported with a transportation of dangerous goods placard;

- follow the list of codes in Appendix 3 of *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities* when tracking, reporting, or manifesting oilfield waste; and

- if contaminants are present, characterize the water. If the properties are deemed dangerous, as outlined in *Directive 058*, then use the Alberta Oilfield Waste Manifest Form and adhere to manifesting requirements outlined in section 8 of *Directive 058* when transporting the waste within Alberta.

ALBERTA UTILITIES COMMISSION

Alberta Electric System Operator 2020 Balancing Pool Consumer Allocation Rider F Application, AUC Decision 24982-D01-2019

Rates - AESO Balancing Pool Consumer Allocation Rider F

In this decision, the AUC considered the application by the Alberta Electric System Operator ("AESO") for its 2020 Balancing Pool consumer allocation Rider F. The AUC approved the AESO's requested $2.50 per megawatt hour ("MWh") Rider F charge to all demand transmission service ("DTS") and demand opportunity service ("DOS") market participants, with the exception of the City of Medicine Hat and BC Hydro at Fort Nelson, for metered energy from January 1, 2020, through December 31, 2020.

Background

The Balancing Pool is a corporation established by Section 75 of the *Electric Utilities Act* ("*EUA*") to carry out the powers and duties set out therein. Pursuant to Section 82 of the *EUA*, the Balancing Pool must prepare a budget for each fiscal year setting out its estimated revenues and expenses. 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.

Following receipt of the Balancing Pool's "annualized amount," the AESO is required to include this amount in its tariff. The AESO collects (refunds) from (to) market participants the Balancing Pool's annualized amount through Rider F.

Rider F for 2020

On October 2, 2019, the Balancing Pool notified the AESO of a negative annual forecast amount of $160,182,500 for 2020 and approved a charge of $2.50/MWh of consumption.

The AESO applied for approval of a $2.50/MWh Rider F charge to all DTS and DOS market participants, with the exception of the City of Medicine Hat and BC Hydro at Fort Nelson, for metered energy from January 1, 2020, through December 31, 2020.

AUC Findings

The AUC approved the method by which the AESO determined the Rider F charge, and ordered that the annualized amount of negative $160,182,500 provided to the AESO by the Balancing Pool, without modification, is approved for 2020.

It further ordered that the applied-for Balancing Pool Consumer Allocation Rider F charge of $2.50/MWh of metered energy is approved effective January 1, 2020, to December 31, 2020.

Alberta PowerLine Limited Partnership Decision on Application for Review and Variance of Decision 24277-D01-2019 - ATCO Group Inter-Affiliate Code of Conduct Compliance Plan, AUC Decision 24538-D01-2019

Code of Conduct - Utility Definition

In this decision, the AUC considered whether to grant an application (the "Review Application") filed by Alberta PowerLine Limited Partnership ("Alberta PowerLine"), requesting a review and variance of specific findings and a direction in AUC Decision 24277-D01-2019: Alberta PowerLine Limited Partnership, ATCO Group Inter-Affiliate Code of Conduct Compliance Plan (the "Decision"). The AUC granted the Review Application.

The AUC panel that authored the Decision will be referred to as the "Hearing Panel" and the AUC panel that considered the Review Application will be referred to as the "Review Panel."

Background

In the Review Application, Alberta PowerLine identified that energization of the Fort McMurray West 500 kV Transmission Line (the "FMACW Project") occurred on March 28, 2019, and that three months prior to that date (on January 25, 2019), Alberta PowerLine filed an application requesting approval for its compliance plan in accordance with the ATCO Group Inter-Affiliate Code of Conduct ("ATCO Group Code").

In the Decision, which was issued on March 26, 2019, the Hearing Panel approved the Alberta PowerLine Inter-Affiliate Code of Conduct Compliance Plan (the "APL Compliance Plan") as filed, and directed Alberta PowerLine to prepare and file an annual compliance report for the 2018 calendar year (the "Direction").

In the Review Application, Alberta PowerLine clarified that it did not seek a review of the AUC's approval of the APL Compliance Plan or any aspect of the Decision other than "the Commission's determination in paragraph 18 of the Decision apparently classifying APL [Alberta PowerLine] as a 'utility' in 2018, and the resulting direction that APL file an annual compliance report for the 2018 calendar year by virtue of such classification".

Paragraph 18 of the Decision stated:

> The Commission is of the view that a compliance plan should have been in place throughout the project, rather than just prior to the commencement of operations. Although there was no compliance plan in place, the Commission notes that the ATCO Electric inter-affiliate annual report for 2017, identified Alberta PowerLine as a utility affiliate and disclosed the information required by Section 7.6 of the ATCO Electric Inter-Affiliate Code of Conduct Compliance Plan. The Commission is of the view that the ATCO Group Inter-Affiliate Code of Conduct requires compliance for all affiliates regardless of whether a compliance plan is formally in place. The Commission expects that Alberta PowerLine has adhered to the principles and requirements outlined in the proposed Alberta PowerLine Inter-Affiliate Code of Conduct Compliance Plan throughout the construction and development of the project. To support its compliance, the Commission directs Alberta PowerLine to prepare and file an annual compliance report for the 2018 calendar year, in accordance with Section 7.6 of the proposed Alberta PowerLine Inter-Affiliate Code of Conduct Compliance Plan with the Commission no later than April 30, 2019.

<u>AUC's Review Process</u>

The Review Panel outlined the AUC's discretionary authority to review its own decisions, and the two-stage review process set out under AUC Rule 016. In the first stage, a review panel must decide whether there are grounds to review the original decision. If there are grounds to review the decision, it moves to the second stage of the review process where the AUC holds a hearing or other proceeding to decide whether to confirm, vary, or rescind the original decision.

The Review Panel determined that it would consider both steps of the Review Application in a single proceeding.

<u>Grounds for Review</u>

In the Review Application, Alberta PowerLine argued that the Hearing Panel erred in directing it to prepare and file an annual compliance report for 2018. Alberta PowerLine expressed its understanding that the Direction was based on the Hearing Panel's determination that Alberta PowerLine should have had a compliance plan in place throughout the entire FMACW Project, including before construction was complete. This determination was, in turn, based on the Hearing Panel's mistaken belief that Alberta PowerLine was identified as an "affiliate utility" in the ATCO Electric inter-affiliate annual report for 2017 ("ATCO Electric Compliance Report").

Alberta PowerLine argued, in fact, ATCO Electric did not identify Alberta PowerLine as a "utility affiliate" in the ATCO Electric Compliance Report.

Alberta PowerLine further argued that the Hearing Panel's characterization of Alberta PowerLine as a utility affiliate prior to the energization of the FMACW Project was inconsistent with the AUC's express finding in Decision 20272-D01-2016. In that decision, the AUC considered how Alberta PowerLine should be characterized for the purposes of the ATCO Group Code and found:

> The Commission considers that while Alberta PowerLine may become (or otherwise be deemed to become) a utility as defined in the ATCO Inter-Affiliate Code of Conduct <u>upon completion of the WFMAC, it does not currently qualify as such</u> because it does not fall under the definition of either a "public utility" as defined at Section 1(i) of the *Public Utilities Act*, or an "electric utility" as defined at Section 1(o) of the *Electric Utilities Act*. (emphasis by Alberta PowerLine)

Alberta PowerLine argued that it was clear from the AUC's analysis of both the *Public Utilities Act* and the *Electric Utilities Act* leading to the above determination that Alberta PowerLine was a "non-utility affiliate" during the construction of the FMACW Project and became a "utility affiliate" on March 28, 2019, when the FMACW Project was complete, and the line was energized.

In its stage 2 submissions, Alberta PowerLine further outlined why it was not a "utility" prior to FMACW energization; its reliance on the AUC's finding in Decision 20272-D01-2016; and its inability to comply with the Direction as a result of this reliance.

Review Panel Findings

In reviewing the record, the Review Panel made note of two aspects of the ATCO Group Code in particular. First, all ATCO utilities are required to comply with the code, as are all their affiliates to the extent they interact with the utilities, but it is the utility that is responsible for compliance by its affiliates.

Second, the Review Panel noted that it is the utility, not its affiliates, that is required to appoint a compliance officer, prepare a compliance plan, and file a compliance report. It is the utility's compliance plan and compliance report that are required to address compliance by affiliates of the utility with respect to interactions with the utility.

The Review Panel found that given provisions of the ATCO Group Code, and most particularly the requirement for utilities, not affiliates, to prepare and file a compliance report, it was implicit in the Decision that the Hearing Panel concluded that Alberta PowerLine was a utility for the purpose of the ATCO Group Code in 2018: a period prior to the anticipated date of energization in March 2019.

The Review Panel found that Alberta PowerLine satisfied the first stage of review.

With regard to the second stage of review, the Review Panel was satisfied that a variance of paragraph 18 of the Decision was warranted. It accepted that it was reasonable for Alberta PowerLine to have relied on the statement in Decision 20272-D01-2016, which found that Alberta PowerLine would not be a utility until completion of the FMACW Project.

The Review Panel also accepted Alberta PowerLine's assertion that as a consequence of its reasonable reliance on the AUC's finding in Decision 20272-D01-2016, Alberta PowerLine was unable to fully comply with the Direction contained in paragraph 18 of the Decision and more specifically, the requirement to retroactively satisfy the informational requirements of the ATCO Group Code for the preparation of a 2018 compliance report.

The Review Panel was satisfied that the Decision ought to be varied by deleting the second bullet of paragraph 1 and deleting paragraph 18 of the Decision, which also had the effect of rescinding the Direction.

AltaLink Management Ltd. - 2014-2015 Deferral Accounts Reconciliation Second Compliance Filing, AUC Decision 24919-D01-2019

Rates - Compliance Filing - Deferral Accounts Reconciliation

In this decision, the AUC set out its determinations regarding the application by AltaLink Management Ltd. ("AML") for its 2014-2015 deferral accounts reconciliation second compliance filing. The AUC approved AML's request to collect $119.4 million through a one-time charge to the Alberta Electric System Operator ("AESO").

Background

On January 23, 2019, the AUC issued Decision 22542-D02-20191 regarding AML's 2014 and 2015 deferral accounts reconciliation application, which required AML to file a reconciliation application with its responses to AUC directions.

AML filed its compliance application on February 15, 2019. In Decision 24329-D01-2019, the AUC ordered AML to provide a second refiling of its 2014 and 2015 deferral accounts reconciliation application.

On September 23, 2019, AML filed an application requesting approval for its 2014-2015 deferral accounts reconciliation second compliance filing.

Issues

In its application, AML applied to collect $119.4 million through a one-time charge to the AESO. The deferral accounts settled included the following charges for 2014 and 2015:

Long term debt	$2.0 M
Taxes other than income taxes	$1.3 M
Annual structure payments	$0.8 M
DA capital	$102.8 M
Heartland land costs net of sale proceeds	$2.9 M
Rule 23 interest (carrying costs)	$9.6 M
Total Adjustments plus interest	**$119.4 M**

In its application, AML prepared responses to AUC directions from Decision 24329-D01-2019. The AUC found that AML adequately responded to those directions, and approved AML's adjustments as filed.

AML also applied to collect an additional $1.0 million related to carrying costs under Rule 023. AML stated that the $8.6 million in carrying costs approved by the AUC in Decision 24329-D01-2019 was only calculated up to the end of June 2019. AML requested that the calculation of the final carrying-cost amount be extended to the date of issuance of the AUC's final decision and that its request to collect $9.6 million assumed a final decision from the AUC by the end of October 2019.

The AUC noted that the award of carrying costs pursuant to Rule 023 is a discretionary award. It found AML's request for an additional $1.0 million in carrying costs reasonable in the circumstances given that the same $91.7 million was still to be recovered from the AESO. The AUC approved AML's request for carrying costs in the amount of $9.6 million.

***ATCO Electric Ltd. 2018 Annual Transmission Access Charge Deferral Account True-Up,* AUC Decision 24779-D01-2019**

Rates - True-Up Application - Transmission Access Charge

In this decision, the AUC considered an application by ATCO Electric Ltd. ("ATCO Electric") requesting approval of its 2018 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts in accordance with Rule 023: *Rules Respecting Payment of Interest*. The 2018 TACDA true-up resulting in a collection from customers of $21.092 million was approved as filed, by way of a Rider G. This rider came into effect on January 1, 2020.

Background

On July 26, 2019, ATCO Electric filed an application with the AUC requesting approval of its 2018 annual TACDA true-up by way of a Rider G.

All electric distribution companies ("DFOs") 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 ATCO Electric'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 ATCO Electric pays to the AESO in that year.

In accordance with the provisions of the performance-based regulation ("PBR") framework approved in Decision 2012-237, ATCO Electric's TACDA is a dollar-for-dollar flow through of the AESO tariff charges for the duration of the 2013-2017 PBR term. The AUC adopted the same provision for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata).

ATCO Electric's Application

ATCO Electric applied for a net 2018 TACDA collection of $21.092 million from customers. It proposed to collect its 2018 TACDA true-up amount by way of a Rider G to be in effect from January 1, 2020, to December 31, 2020.

2018 TACDA true-up amount and Rider G rate

The components of the 2018 true-up amount included the true-up of the 2016 TACDA rider, the true-up of the three amounts arising from the various 2018 AESO charges, and carrying costs associated with those amounts. They are described further below.

2016 TACDA Rider True-Up

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. ATCO Electric's 2016 TACDA rider, approved in Decision 22875-D01-2017, resulted in a net refund of $9.020 million.

ATCO Electric stated that it refunded $9.707 million over the refund period. The difference results in a collection of $0.687 million.

System Access Service ("SAS") Deferral True-Up

The purpose of a SAS deferral true-up is to reconcile the actual transmission access revenue received from customers to the actual transmission access costs paid to the AESO. ATCO Electric indicated that its total 2018 transmission access revenues for distribution connected customers, including revenues received through its quarterly TACDA true-up riders, amounted to $328.378 million, which, compared to the total costs of $331.631 million, results in a collection from customers of $3.253 million.

AESO Deferral Account Reconciliation ("DAR") True-Up

Under section 14(3) of the *Electric Utilities Act*, "The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation." Accordingly, any variances arising between the actual costs the AESO incurs and the forecast amounts, recovered through its rates based on forecast volumes, are refunded to, or recovered from, market participants by way of the AESO DAR, typically undertaken on an annual basis. In turn, the DFOs flow through these collections or refunds to customers in their service areas.

In this application, ATCO Electric requested approval to include the collection related to the 2017-2018 AESO DAR of $25.575 million. When combined with a $7.764 million refund associated with the 2016 AESO DAR, this amounted to a net collection of $18.012 million.

Balancing Pool True-Up

The AUC noted that the purpose of ATCO Electric'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 2018, the AESO collected $38.957 million from ATCO Electric. Due to differences between forecast and actual billing determinants, ATCO Electric collected $39.589 million from its customers in 2018, necessitating a net refund of $0.632 million. ATCO Electric proposed to allocate the Balancing Pool true-up to all customer rate classes, with the exception of Rate T31, based on the original amount collected in 2018.

Carrying Costs

ATCO Electric calculated carrying costs on outstanding amounts related to the true-up balances in accordance with Rule 023*: Rules Respecting Payment of Interest*. The total carrying costs amounted to a net refund of $0.227 million.

<u>AUC Findings</u>

The AUC approved a net collection of $21.092 million.

<u>Rider Implementation Period and Customer Bill Impacts</u>

The AUC reviewed the total bill impacts of the proposed Rider G and found the rate impacts to be reasonable and unlikely to cause rate shock.

<u>Rider C Analysis</u>

The AUC found that converting the approved percentage based Rider C rates to the equivalent $/MWh charge remains appropriate in the calculation of the AESO Rider C allocation.

<u>Rider G Rate</u>

For the purposes of this decision, the AUC accepted ATCO Electric's proposal to calculate the Rider G rate using the 2020 forecast billing determinants. In making this determination, the AUC noted that the 2018 TACDA rider would eventually be trued up to ensure the approved amounts were collected from, or refunded to, customers (similar to how the 2016 rider was trued up in the present proceeding).

ATCO Electric Ltd. 2020 Balancing Pool Adjustment Rider (Rider B), **AUC Decision 25013-D01-2019**

Rates - Balancing Pool Adjustment

In this decision, the AUC approved ATCO Electric's 2020 Balancing Pool adjustment rider as filed, effective January 1, 2020.

<u>Background and Details of the Application</u>

Under the *Electric Utilities Act* ("*EUA*"), the benefits and costs associated with the Balancing Pool are shared among all electricity customers in Alberta.

Accordingly, 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 remitted to (or collected from) electricity consumers over the year. Pursuant to Section 82 of the *EUA*, these distributions or charges are made through the Alberta Electric System Operator ("AESO") tariff, by way of Rider F.

The amount to be remitted or collected by way of Rider F is known as the consumer allocation and applies to all market participants who receive system access service under rate demand transmission service ("DTS") and rate demand opportunity service ("DOS") from the AESO. The allocation among participants is based on the amount of electric energy consumed annually. Because the AESO's Rider F is calculated at the substation point of delivery ("POD") level and a utility's Balancing Pool allocation rider is applied at the customer meter level, in calculating a utility's Balancing Pool allocation rider, the AESO's charge rate must be adjusted to account for distribution losses.

In its application, ATCO Electric detailed the calculation of Rider B for all rate classes. More specifically, ATCO Electric detailed its proposed adjustment to the AESO Rider F charge of $2.50/MWh for distribution losses for all rate classes with the exception of transmission-connected classes (T31/T33), which are billed on a flow through basis. Metering and billing of these customers ensure that the amounts billed are consistent with the $2.50/MWh charge. ATCO Electric noted that consistent with previous Rider B applications, in setting its Rider B rates, it will continue to take into account the effects of distribution losses by rate class as approved in Decision 2011-483, ATCO Electric's 2011 Phase II application.

<u>AUC Findings</u>

The AUC noted that ATCO Electric calculated its proposed Rider B based on the AESO's 2020 Rider F consumer allocation charge of $2.50/MWh, adjusted for ATCO Electric's estimated 2020 distribution losses, consistent with the methodology used in other previous Rider B decisions. The AUC found the assumptions ATCO Electric relied on to be reasonable and its calculations correct.

The AUC acknowledged that ATCO Electric filed an updated Phase II application with updated distribution loss factors, which was currently before the AUC in proceeding 24747. It directed ATCO Electric, in its next Rider B application, to utilize any updated distribution line loss figures approved by the AUC in that proceeding.

The AUC approved ATCO Electric's 2020 Rider B effective January 1, 2020, noting that ATCO Electric's 2020 Rider B will eventually be trued up to ensure the approved amounts were collected from customers.

***ATCO Gas and Pipelines Ltd. Franchise Agreement with the Village of Beiseker*, AUC Decision 24998-D01-2019**

Gas - Municipal Franchise Agreement

In this decision, the AUC considered an application (the "Application") filed by ATCO Gas South ("ATCO") requesting approval of a natural gas franchise agreement renewal (the "Agreement") with the Village of Beiseker ("Beiseker"). The AUC approved the Application.

<u>Proposed Franchise Agreement and Franchise Fee Rate Rider Schedule</u>

Under the Agreement, Beiseker would grant ATCO the exclusive right within the municipal service area to provide natural gas distribution service. The Agreement would have a term of ten years.

The Agreement proposed a franchise fee of 16.00 percent. ATCO advised that this would result in a continuation of an average monthly franchise fee of $6.70 for an average residential customer. The proposed franchise fee would be less than the 35 percent franchise fee cap previously approved by the AUC. Under the Agreement, Beiseker would have the option to change the franchise fee percentage annually upon written notice to ATCO and subject to AUC approval. The franchise fee would be a payment in lieu of municipal property taxes pursuant to section 360 of the *Municipal Government Act* ("*MGA*").

The Agreement included changes to the standard natural gas franchise agreement template, approved by the AUC in Decision 20069-D01-2015. The parties agreed that ATCO would collect from consumers and pay to Beiseker a franchise fee in lieu of taxes. The municipal taxes clause of the standard franchise agreement template was removed from the Agreement

Legislative Framework

Section 45 of the *MGA* deals with franchise agreements and provides, among other things, that a municipal council may, by agreement, grant a right, exclusive or otherwise, to a person to provide utility service in all or part of the municipality. The grant cannot exceed 20 years. Section 45(3) provides that before such an agreement is made, amended or renewed, it must be approved by the AUC. Similarly, section 49(1) of the *Gas Utilities Act* ("*GUA*") provides that no franchise granted to any owner of a gas utility by any municipality within Alberta is valid until approved by the AUC.

In considering whether to approve the franchise, the AUC must determine whether the proposed agreement is necessary and proper for the public convenience, and properly serves the public interests, as set out in section 49(2) of the *GUA*.

AUC Findings

The AUC noted that the proposed franchise fee of 16.00 percent was below the 35 percent fee cap previously approved by the AUC. Also, the franchise fee percentage of 16.00 percent had been approved in Disposition 24115-D01-2018. The AUC also noted the term of the Agreement was within the 20-year maximum specified by the *MGA*.

The AUC considered the proposed changes to the standard gas franchise agreement template and noted that Beiseker had been paid franchise fees in lieu of taxes in previous franchise agreements. The AUC also noted that Beiseker had this option pursuant to Section 360 of the *MGA*.

The AUC considered that the right granted to ATCO by Beiseker set forth in the Agreement was necessary and proper for the public convenience and would properly serve the public interests. Accordingly, the AUC approved the Agreement as filed. The AUC also approved ATCO's Rate Rider A amount of 16.00 percent for customers in the Village of Beiseker, commencing on the date the proposed franchise agreement becomes effective.

***AUC Strategic Plan 2019-2022 Finalized*, AUC November 26, 2019 Announcement**

Announcement - AUC Strategic Plan

The AUC announced that it finalized its three-year strategic plan, which will guide its efforts in the short- to medium-term as Alberta's independent utilities regulator.

The plan marks a new approach for the AUC intended to reflect fundamental changes underway in the utilities sector, revolving around the impact of increasing technology change and shifting societal expectations. It also addresses emerging challenges centred on utility infrastructure and its cost; increasing efficiency and limiting regulatory burden; supporting conditions for competition and efficient markets; and developing, attracting and retaining the right people to meet the demands of a changing utility and regulatory environment.

As part of the plan's efficiency and limiting regulatory burden theme, the plan also calls for an annual industry impact assessment to evaluate the effectiveness of AUC processes and to ensure they reflect the principles outlined in the *Red Tape Reduction Act*. The assessment will be used to build an annual AUC report card, replacing the AUC's annual review.

***Canadian Utilities Limited and Genesee Lake Holding Corp. Application for the Sale of Alberta PowerLine Limited Partnership*, AUC Decision 24792-D01-2019**

Electricity - Sale of Interest

In this decision, the AUC considered an application by Canadian Utilities Limited ("CUL") for approval of the sale of its interest in Alberta PowerLine Limited Partnership ("APL") to Genesee Lake Holding Corp. ("GLHC") The AUC approved the sale of CUL's interest.

Background

APL is the owner and operator of the Fort McMurray West 500 kilovolt Transmission Project pursuant to a Project Agreement dated September 28, 2017, with the Alberta Electric System Operator to provide electric transmission service between the Edmonton and Fort McMurray regions. CUL owned an 80 percent indirect interest in APL through its wholly owned subsidiary, 2200427 Alberta Ltd. QSI Finance Canada ULC ("Quanta") owned the other 20 percent indirect equity interest in APL.

CUL entered into definitive agreements, along with Quanta, for the sale of 100 percent of its interest in APL. CUL then applied to the AUC for approval to sell its interest in APL to GLHC.

Relevant Legislation

Sections 101(2)(a), 101(2)(d)(i) and (ii) of the *Public Utilities Act* ("*PUA*") state that no owner of a public utility designated under subsection shall: issue any of its shares or stock; issue any bonds or other evidences of indebtedness; sell, lease or mortgage its property; or merge or consolidate property outside of the ordinary course of the owner's business unless approved by the AUC. Section 26(2)(d)(i) of the *Gas Utilities Act* ("*GUA*") states that no owner of a gas utility shall sell, lease, mortgage, or otherwise dispose of its property or merge or consolidate its property without AUC approval.

AUC Findings

The AUC stated that the central question in deciding whether to approve a transaction outside of the ordinary course of business under the sections noted above is whether customers are harmed by the transaction. The AUC noted that the no-harm test and the factors considered by the AUC have evolved over the years, and the test now reflects the following:

- customers are, to the maximum extent possible, to be protected against any negative ramifications arising from the transactions;
- customers are not entitled to a level of post-transaction regulatory certainty they would not have realized if the transaction had not been approved; and
- customers are at least no worse off after the transaction is completed after consideration of the potential positive and negative impacts of the proposed share transactions.

The AUC found that the sale of CUL's interest would not have potentially harmful operational effects on regulated customers. The AUC also found that approval of the sale of CUL's interest would not result in any financial harm to customers. The AUC, therefore, found that the no-harm test has been satisfied.

The AUC approved CUL's sale or disposal of certain property pursuant to section 101(2)(d)(i) of the *PUA* and section 26(2)(d)(i) of the *GUA*.

***Enhancement to the eFiling System to Support Confidential Documents in Proceedings*, AUC November 13, 2019 Announcement**

Announcement - Confidentiality - AUC Rule 001

The AUC announced a major enhancement to the eFiling System to support the exchange of confidential documents between proceeding participants. It expects to release the enhancement in the first quarter of 2020, which will negate the need for the manual exchange of USB flash drives and provide an efficient and secure way to share confidential documents with proceeding participants approved by the disclosing party.

The key enhancements include the ability to:

- submit confidential application or file documents that remain on the confidential record;
- designate a confidential administrator(s) in your organization that will be responsible for determining which individuals or representatives should have access to your confidential documents for each confidential proceeding;
- submit a public motion for confidentiality filing as well as the ability to upload associated confidential motion documents by the disclosing party;
- allow the AUC to issue a public confidentiality ruling on one or more motions for confidentiality that specifies what information is to remain confidential and identify any parties to be excluded from submitting a confidentiality undertaking;
- allow proceeding participants to submit a confidentiality undertaking for each individual requiring access to the confidential record with notification to the disclosing party's confidential administrator to grant or deny access to the confidential record for the individual;
- search for confidential documents for approved users;
- submit statutory declarations that revoke access to the confidential record;

- extend access to the confidential material to approved users on any related compliance, costs or review and variance proceedings; and
- allow the AUC to issue both a public version and a confidential version of the decision.

In conjunction with the release, some minor amendments to AUC Rule 001: Rules of Practice will be made to update procedures that reflect the new capabilities on the eFiling System.

ENMAX Power Corporation - 2018 Annual Transmission Access Charge Deferral Account True-Up, AUC Decision 24807-D01-2019

Rates -True-up - Transmission Access Charge

In this decision, the AUC considered an application by ENMAX Power Corporation ("ENMAX") requesting approval of its 2018 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts in accordance with Rule 023: *Rules Respecting Payment of Interest*. The AUC approved a 2018 TACDA true-up net collection amount of $37,788,326 by way of a transmission access charge ("TAC") rider effective January 1, 2020.

Background

On August 9, 2019, ENMAX filed an application with the AUC requesting approval of its 2018 annual TACDA true-up by way of a TAC rider.

All electric distribution companies ("DFOs") 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 is a dollar-for-dollar flow through of the AESO tariff charges for the duration of its 2015-2017 PBR term. The AUC adopted the same provision for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata).

Details of the Application

ENMAX applied for a net 2018 TACDA collection from customers of $37,788,326. ENMAX proposed to collect its 2018 TACDA true-up amount by way of a TAC rider to be in effect from January 1, 2020, to December 31, 2020.

2018 TACDA True-Up Amount and TAC rider rate

The components of the 2018 TACDA true-up amount included the true-up of the portion of the 2016 TAC rider, the system access service ("SAS") deferral true-up, the AESO deferral account reconciliation ("DAR") true-up, the Balancing Pool true-up, and carrying costs associated with these amounts.

2016 TAC Rider True-Up

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. ENMAX's 2016 TACDA rider, approved in Decision 22871-D01-2017, resulted in a net refund of $16.696 million. ENMAX indicated that it refunded $16.890 million over the refund period. The difference results in a collection of $0.194 million.

SAS Deferral True-Up

The purpose of an SAS deferral true-up is to reconcile the actual transmission access revenue received by ENMAX from its customers through both the base SAS rates and quarterly TAC true-up riders, to the actual transmission access costs paid to the AESO. ENMAX calculated its 2018 SAS deferral true-up as the difference between the actual transmission costs of $335.143 million and the sum of SAS base revenue and quarterly TAC revenue of $167.056 million and $152.313 million, respectively. The result was a net collection from customers of $15.773 million.

AESO DAR True-Up

Under section 14(3) of the *Electric Utilities Act*, "The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation." Accordingly, any variances arising between the actual costs the AESO incurs and the forecast amounts, recovered through its rates based on forecast volumes, are refunded to or recovered from market participants by way of the

AESO DAR, typically undertaken on an annual basis. In turn, the DFOs flow through these collections or refunds to customers in their service areas.

On September 30, 2018, ENMAX received an AESO DAR invoice that involved a refund of $3.319 million. In addition, on September 27, 2019, the AESO applied to the AUC requesting approval for its deferral account balances for 2017 and 2018, and changes to its deferral account balances from 2006 to 2016. The proposed reconciliation resulted in a $24.255 million charge to ENMAX. The charge, along with the refund amount of $3.319 million from September 2018, results in a total collection from customers of $20.937 million.

Balancing Pool True-Up

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 2018, ENMAX paid $29.883 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 $29.958 million from its customers in 2018, necessitating a net refund of $0.075 million.

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*. ENMAX calculated the total carrying costs to be a net collection of $0.959 million.

AUC Findings

The AUC approved a net collection of $37,788,326.

Rider Implementation Period and Customer Bill Impacts

The AUC reviewed the total bill impacts and found the rate impacts to be reasonable and unlikely to cause rate shock. It approved the 2018 TAC rider implementation effective January 1, 2020.

Rider C Analysis

Based on the Rider C analysis provided, the AUC found that converting the approved percentage based Rider C rates to the equivalent $/MWh charge remains appropriate in the calculation of the AESO Rider C allocation.

TAC Rider Rate

For the purpose of this decision, the AUC accepted ENMAX's proposal to calculate TAC rider rates using the 2020 forecast billing determinants. In making this determination, the AUC noted that the 2018 TAC rider would eventually be trued up to ensure that the approved amounts were collected from, or refunded to, customers (similar to the 2016 rider true-up in the current proceeding).

***EPCOR Distribution & Transmission Inc. 2018 Annual Transmission Access Charge Deferral Account True-Up,* AUC Decision 24816-D01-2019**

Rates - True-Up - Transmission Access Charge

In this decision, the AUC considered an application by EPCOR Distribution & Transmission Inc. ("EPCOR") requesting approval of its 2018 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts in accordance with Rule 023: *Rules Respecting Payment of Interest*. The 2018 TACDA true-up resulting in a collection from customers of $15.23 million was approved as filed, by way of a Rider J. This rider came into effect starting January 1, 2020.

Background

On August 15, 2019, EPCOR filed an application with the AUC requesting approval of its 2018 annual TACDA true-up by way of a Rider J.

All electric distribution companies ("DFOs") 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 EPCOR'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 EPCOR pays to the AESO in that year.

In accordance with the provisions of the performance-based regulation ("PBR") framework approved in Decision 2012-237, EPCOR's TACDA is a dollar-for-dollar flow through of the AESO tariff charges for the duration of its 2013-2017 PBR term.

The AUC adopted the same provision for the 2018-2022 PBR term in Decision 20414-D01-2016 (Errata).

Details of the Application

EPCOR applied for a net 2018 TACDA collection of $15.23 million from customers. EPCOR proposed to collect its 2018 TACDA true-up amount by way of a Rider J to be in effect from January 1, 2020, to December 31, 2020.

2018 TACDA True-Up amount and Rider J rate

The components of the 2018 true-up amount include prior transmission access charge ("TAC") riders, the system access service ("SAS") deferral true-up, AESO deferral account rider ("DAR") true-up, the Balancing Pool true-up, and carrying costs associated with those amounts.

Deferral Account Rider True-Up

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. EPCOR's 2016 TACDA rider, approved in Decision 22887-D01-2017, resulted in a net refund of $12.28 million. EPCOR stated that it refunded $12.26 million over the refund period. The difference results in a refund of $0.02 million.

SAS Deferral True-Up

The purpose of a SAS deferral true-up is to reconcile the actual transmission access revenue received from customers to the actual transmission access costs paid to the AESO. EPCOR's total 2018 transmission access revenues for distribution connected customers, including revenues received through its quarterly TACDA true-up riders, amounted to $253.37 million, which, when compared to total costs of $250.82 million, results in a refund to customers of $2.55 million.

AESO DAR True-Up

Under section 14(3) of the *Electric Utilities Act*, "The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation." Accordingly, any variances arising between the actual costs the AESO incurs and the forecast amounts, recovered through its rates based on forecast volumes, are refunded to, or recovered from, market participants by way of the AESO DAR, typically undertaken on an annual basis. In turn, the DFOs flow through these collections or refunds to customers in their service areas.

On September 27, 2019, the AESO applied to the AUC for a 2017-2018 DAR requesting to charge or refund amounts from market participants on an interim refundable basis by December 3, 2019. The reconciliation amount to EPCOR was a collection of $19.0 million. This amount was broken down between non-direct connect customers ($18.0 million) and direct connect customers ($1.0 million). EPCOR explained that it included the AESO's proposed refund in this application because of the materiality of the amount.

Balancing Pool True-Up

The purpose of EPCOR'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 2018, the AESO collected $23.38 million from EPCOR. Due to the differences between forecast and actual billing determinants, EPCOR collected $23.42 million from its customers in 2018, necessitating a net refund of $0.04 million. EPCOR proposed to allocate the Balancing Pool true-up to all customer rate classes, with the exception of direct connect customers, based on actual 2018 energy consumption by rate class.

Carrying Costs

EPCOR 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. The total carrying costs amounted to a net refund of $0.15 million.

AUC Findings

The AUC approved a net collection of $15.23 million.

Rider Implementation Period and Customer Bill Impacts

The AUC reviewed the total bill impacts of the proposed Rider J and found the rate impacts to be reasonable and unlikely to cause rate shock. It approved the Rider J effective January 1, 2020.

Rider C Analysis

The AUC found that converting the approved percentage based Rider C rates to the equivalent $/MWh charge remains appropriate in the calculation of the AESO Rider C allocation.

Rider J Rate

For the purposes of this decision, the AUC accepted EPCOR's proposal to calculate the Rider J rate using the 2020 forecast billing determinants. In making this determination, the AUC noted that the 2018 TAC deferral account rider would eventually be trued up to ensure the approved amounts were collected from or refunded to customers.

FortisAlberta Inc. 2018 Annual Transmission Access Charge Deferral Account True-Up, AUC Decision 24729-D01-2019

Rates - True-Up - Transmission Access Charge

In this decision, the AUC considered an application by FortisAlberta Inc. ("Fortis") requesting approval of its 2018 annual transmission access charge deferral account ("TACDA") true-up and carrying costs on the true-up amounts in accordance with Rule 023: *Rules Respecting Payment of Interest*. The AUC approved the 2018 TACDA true-up net refund amount of $27.033 million as filed, by way of a base 2020 transmission adjustment rider ("TAR") to be in effect from January 1, 2020, to December 31, 2020 ("2020 TAR").

The AUC also considered Fortis's proposal to modify the application of the quarterly transmission adjustment rider ("QTAR") as applied to irrigation customers (Rate 26) and the presentation of quarter-over-quarter bill impact analysis for these customers. The AUC accepted Fortis's proposal to set the QTAR for irrigation customers to zero in Quarter 1 (Q1) and Quarter 4 (Q4) as energy usage by irrigation customers is minimal during these periods. It also accepted Fortis's proposal to use previous year quarterly result comparators as a basis for completing quarter-over-quarter bill impact analysis when that comparator is more relevant than the previous quarter from the current year.

Background

Fortis filed its application on August 16, 2019.

All electric distribution companies ("DFOs") 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 Fortis'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 Fortis pays to the AESO in that year.

Details of the Application

Fortis applied for a net 2018 TACDA refund to customers of $27.033 million. The allocation of this net refund amount to customer rate classes, as proposed by Fortis, is set out in the following table.

Rate class		**Total true-up amount ($000)**
1	Residential	(2,415)
2	FortisAlberta Farm	(768)
3	REA Farm / Irrigation	(24)
4	FortisAlberta Irrigation	(2,194)
5	Exterior Lighting	(21)
6	Small General Service	187
7	Oil and Gas	195
8	General Service	(17,649)
9	Large General Service	(4,430)
10	Opportunity Transmission	-
11	Transmission-Connected Customer	86
12	Total	**(27,033)**

Calculation of the True-Up Amount

The components of the 2018 TACDA true-up included the true-up of a 2016 rider related to the AESO charges, and the true-up of the four amounts arising from the various 2018 AESO charges. This included the system access service ("SAS") deferral true-up, AESO deferral account reconciliation ("DAR") true-up, Balancing Pool true-up and border customer deferral account true-up, as well as carrying costs associated with those amounts.

TACDA Rider True-Up

The AUC noted 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 2016 annual TACDA true-up refund of $30.416 million, approved in Decision 22883-D01-2016, and the actual amount refunded of $31.297 million, resulting in the true-up of $0.881 million on an aggregate basis.

SAS Deferral True-Up

The AUC noted that the purpose of a SAS 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 2018 actual transmission access costs, excluding transmission costs for transmission-connected Rate 65 customers, were $621.708 million, while its actual transmission access revenues for distribution connected customers, including revenues received through its quarterly TACDA riders, were $636.336 million. Fortis, therefore, applied to refund $14.628 million to customers.

AESO DAR True-Up

Under section 14(3) of the *Electric Utilities Act*, “The Independent System Operator must be managed so that, on an annual basis, no profit or loss results from its operation.” Accordingly, any variances arising between the actual costs the AESO incurs and the forecast amounts, recovered through its rates based on forecast volumes, are refunded to or recovered from market participants by way of the AESO DAR, typically undertaken on an annual basis. In turn, the DFOs flow through these collections or refunds to customers in their service areas.

In Decision 23802-D02-2018, the AUC approved the AESO’s 2016 DAR. Fortis was refunded $16.884 million. Of this amount, $5.08026 million was refunded to transmission-connected service Rate 65 customers, while Fortis applied in this application for the remaining balance of $11.804 million to be refunded to distribution connected customers.

Balancing Pool True-Up

The AUC noted that the purpose of Fortis’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 2018, Fortis paid $55.483 million to the Balancing Pool. Due to differences between forecast and actual billing determinants (also known as billing units – in this case, energy flowed through Fortis’s distribution system), Fortis collected $55.660 million from its customers in 2018, necessitating a net refund of $0.178 million.

Border Customer Deferral

Border customers are customers in Fortis’s 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’s 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 indicated that in 2018, the total payments pertaining to service to its border customer suppliers were $0.658 million, while the receipts from the Power Pool were ($0.382) million, resulting in a collection of $0.276 million.

Carrying Costs

Fortis calculated carrying costs on outstanding amounts related to the true-up balances in accordance with Rule 023. The total carrying costs amounted to a net refund of $1.580 million.

AUC Findings

The AUC approved a net refund of $27.033 million, as calculated by Fortis in its application and the resulting true-up amount for each rate class.

2020 TAR

Fortis proposed to refund the 2018 TACDA true-up amount by way of the base 2020 TAR to be applied over the 12-month period from January 1, 2020, through to December 31, 2020.

In the application, Fortis did not calculate its 2020 TAR rates as it did not have the forecast base 2020 transmission access charges, which would be determined in its 2020 annual PBR rate adjustment filing. Fortis subsequently included the 2020 TAR percentages, calculated as part of its 2020 annual PBR rate adjustment filing.

The AUC noted that the 2020 TAR percentage rate would be determined in Fortis’s 2020 annual PBR rate adjustment filing in proceeding 24876.

Rider C Analysis

Based on the Rider C analysis provided, the AUC found that converting the approved percentage based Rider C rates to the equivalent $/MWh charge remains appropriate in the calculation of the AESO Rider C allocation.

Irrigation Rate Class QTAR Proposal

As part of the application, Fortis included a proposal to make adjustments to the application of the QTAR mechanism in 2020; specifically, Fortis proposed to make adjustments to the way the rider is applied to irrigation rate class customers (Rate 26) and the presentation of the quarter-over-quarter bill impact analysis. Fortis proposed that the "Q1 and Q4 QTAR rates for the Irrigation rate class (Rate 26) be set to $0/MWh and not used in the quarter-over-quarter bill impact comparison in the respective Quarterly AESO DTS Deferral Account Applications." Fortis explained that the proposed change, "is a result of the seasonality of the irrigation season and QTAR rate being collected on the majority of the energy from April 1 to October 31 with minimal energy being consumed by the irrigation rate class during Q1 and Q4."

The AUC found the Fortis proposal reasonable and approved its use in future QTAR applications.

CANADA ENERGY REGULATOR

NOVA Gas Transmission Ltd. Application for Approval of Amendments to the NGTL Gas Transportation Tariff - Temporary Service Protocol, CER Decision RH-002-2019

Gas Transportation - Temporary Service Protocol

In this decision, the CER considered NGTL's Application (the "Application") for approval of amendments to the NGTL Gas Transportation Tariff for the Temporary Service Protocol ("Protocol"). The CER approved the Application as filed, effective September 30, 2019.

Background

On 26 August 2019, NGTL filed the Application pursuant to section 60(1)(b) of the *National Energy Board Act* ("*NEB Act*") for amendments. NGTL submitted in the Application that:

- the effect of the Protocol would be to provide NGTL with flexibility to prioritize interruptible delivery and storage injection over receipt services (interruptible or firm) to manage system constraints during planned outage/maintenance periods at and upstream of Clearwater Compressor Station and Woodenhouse Compressor Station; and

- the Protocol would be utilized only in the summer periods of 2019 (from the date of CER approval through October) and 2020 (April through October).

NGTL requested an effective date for the Protocol of September 3, 2019, or as soon as possible thereafter.

Regulatory Framework

On 28 August 2019, the *Canadian Energy Regulator Act* ("*CER Act*") came into force. Section 36 of the transitional provisions state that applications pending before the National Energy Board ("NEB") immediately before the commencement day are to be taken up before the CER and continued in accordance with the *NEB Act*. Therefore, the CER assessed the Application in accordance with the *NEB Act*.

Sections 62 and 67 of the *NEB Act* state:

> 62. All tolls shall be just and reasonable and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.
>
> 67. A company shall not make any unjust discrimination in tolls, service or facilities against any person or locality.

The CER noted that in previous decisions, the NEB articulated tolling principles that assist in the interpretation and application of these statutory provisions. These include cost-based/user-pay, no acquired rights, and economic efficiency. The CER considered the Application and evidence on the record having regard to these legislated requirements and fundamental tolling principles.

CER Findings

No Unjust Discrimination

The CER found that the Protocol did not result in any unjust discrimination. In making this determination, the CER considered whether shippers that share substantially similar circumstances were being treated equally. The CER was satisfied that, based on the evidence tendered by NGTL, users under substantially similar circumstances would be treated equally. The CER noted that receipt shippers that share geographic and operational circumstances, such as receipt shippers upstream of constraints, will be treated similarly under the conditions of the Protocol.

The CER found that, in this case, it was reasonable to distinguish between receipt and delivery services during curtailments as receipt and delivery services are predominantly situated in different locations of the NGTL system and are impacted differently by constraints on the system.

The CER indicated its findings apply equally to the argument that some storage operators would be favoured over others. The CER was not persuaded that storage operators upstream of the constraints identified in the Protocol operate under similar circumstances as those that exist at East Gate storage locations.

Moreover, the CER noted that the parties supporting the Application represented diverse interests, including producers who could be negatively impacted by curtailments, delivery customers, and an end user.

Economic Efficiency

The CER found that the Protocol was consistent with established tolling principles, particularly the principle of economic efficiency. The CER indicated it views economic efficiency to include the optimization of system use and delivery choices to system users. The CER accepted, in this case, that enhancing access to storage in the summer during planned maintenance events is key to achieving the efficient use of the NGTL system.

The CER found that the existing tariff, without amendment, had the effect of curtailing services in parts of the system not in proximity to the physical constraints and contributed to periods of supply and demand distortions. The CER, therefore, found that efficient system use and services to customers have not been achieved using the current system of curtailments.

The CER found that the Protocol, by enhancing access to storage, would promote economic efficiency and be consistent with the goal that Canadians benefit from efficient energy infrastructure and markets.

The CER noted that it was unnecessary for the CER to make any findings as to the likely impacts of the Protocol on natural gas prices or the broader relevance of price stability within an adjudication of tariff terms. There was no expert evidence tendered in respect of the commodity price issues associated with the Protocol. However, there was ample evidence that economic efficiency would likely be enhanced by the Protocol, even without considering potential commodity price impacts.

The CER further noted that while NGTL is endeavouring to expand its system to address current system constraints, major capital expansions cannot address inefficiencies quickly and in the short-term. In this case, the CER was persuaded that the Protocol was a reasonable short-term solution to enhance storage access during planned summer maintenance events, prior to proposed capacity additions in 2021.

Conclusion

The CER approved the Application on September 26, 2019, with an effective date of September 30, 2019.