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

Capital Power Corp. v Alberta Utilities Commission, 2018 ABCA 437

Permission to Appeal - Dismissed

In this decision, the Alberta Court of Appeal ("ABCA") considered applications by Capital Power Corporation ("Capital Power"), ENMAX Energy Corporation ("ENMAX"), and TransAlta Corporation ("TransAlta") (collectively, the "Applicants") for permission to appeal AUC Decision 790-D02-2015, which considered complaints regarding the ISO line loss rule and methodology.

The ABCA found that the AUC's decision that it could order a remedy or relief to correct for the payment and receipt of unlawful line loss charges and credits did not raise a question of law or jurisdiction which required an appeal to the ABCA. Therefore, the ABCA dismissed the applications for permission to appeal.

Line Losses and Calculating Loss Factors

In Alberta, with respect to line losses and the ISO line loss rule, the ABCA set out the following background:

- When electricity is transmitted across a transmission line, not all of the electricity generated from a power plant will reach load consumers. Some of it will be lost as heat along the way. The difference between the amount of energy put onto the system and the amount of energy ultimately received for consumption is referred to as transmission line losses.

- The owner of the generating unit that produced the electricity, or the owner of the output of that generating unit through a Power Purchase Arrangement ("PPA"), pays the cost of this lost energy, allocated to each based on the methodology set out in the Line Loss Rule.

- While the Alberta Electric System Operator ("AESO") can accurately measure system-wide losses sustained over time, attributing those losses to individual generating units is more complex. Line losses for each generating unit are influenced by a number of related factors, including: the amount of electricity produced by all other generating units; their locations relative to load and to each other; the amount of load on the system at any time; and the capacity of the transmission line(s) linking generating units to the rest of the system.

- The AESO employs a model to estimate line losses for each generating unit, rather than attempting to physically measure each unit's line losses. The methodology generates a loss factor for each unit, which, in turn, is used to determine whether a generating unit adds to or reduces system-wide losses on a net basis.

- Generating units that cause losses on a net basis are issued an invoice whereas generating units that reduce (i.e., save or avoid) losses are given credits.

Brief History of the Line Loss Rule Complaint

Original Complaint

The genesis of the ISO line loss rule saga dates to 2005 when the AESO proposed a new methodology for calculating line losses. Milner first filed its complaint with the AUC's predecessor, the Alberta Energy and Utilities Board (the "EUB"), on August 17, 2005, in respect of the ISO Rule 9.2: Transmission Loss Factors, implemented on January 1, 2006.

The EUB dismissed Milner's complaint. However, the EUB's decision was successfully appealed to the ABCA. The ABCA directed the AUC to reconsider whether the Line Loss Rule contravened section 19 (now section 31) of the *Transmission Regulation*, as alleged by Milner.

In the time between the EUB decision, and the ABCA remitting the decision to the AUC for determination, the Line Loss Rule, the *Transmission Regulation*, and the 2003 version of the *Electric Utilities Act* (the "*2003 EUA*") in force at that time had all been updated, amended or refiled in some form. On June 11, 2012, Milner submitted a second complaint, on a without prejudice basis, in respect of the re-filed line loss Rule. ATCO also submitted a complaint on the same date.

Proceeding 790: Phase 1

The AUC set up a two-phase process to re-hear Milner's complaint: Phase 1 to consider if the Line Loss Rule contravened the *Transmission*

Regulation, and Phase 2 (if necessary) to determine the remedy if a contravention was found.

In the Phase 1 decision (Decision 2012-104), a majority of the AUC panel found that the Line Loss Rule contravened section 19 of the *Transmission Regulation* and upheld Milner's initial complaint as valid. The AUC found that the Line Loss Rule, as amended, was unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory, and inconsistent with and in contravention of the 2003 *EUA* and the relevant portions of the *Transmission Regulation*. The AUC later confirmed these principal findings in a review and variance hearing, resulting in Decision 2014-110. These findings and decisions were comprised of Phase 1 of Proceeding No. 790.

Proceeding 790: Phase 2 Module A

The AUC considered Phase 2 of Proceeding 790 in three modules. In Module A (Decision 790-D02-2015), the AUC determined that it had the jurisdiction to grant relief to correct for the payment of transmission line loss charges found to be unlawful in it's the Phase 1 decisions. The AUC's findings included the following:

(a) the non-compliant provisions of the ISO line loss rule remained in effect and continued to be non-compliant with the *EUA* and the *Transmission Regulation* uninterrupted from January 1, 2006, when the line loss rule came into effect (the "Line Loss Rule");

(b) Milner's complaint had continued uninterrupted since August 17, 2005;

(c) the complaints against the Line Loss Rule satisfied the statutory requirements for the AUC to grant relief from January 1, 2009, forward, under either version of the *EUA*;

(d) the complaint in respect of the Line Loss Rule was regarding the line loss charge components of the ISO tariff, and therefore those components of the ISO tariff were similarly unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory, and inconsistent with and in contravention of the *EUA* and the relevant portions of the *Transmission Regulation*, since 2006;

(e) any remedy the AUC might grant through a tariff-based remedy would not constitute retroactive ratemaking; and

(f) the AUC had jurisdiction to grant a tariff-based remedy or relief under either the *2003 Electric Utilities Act* or, if applicable, it could also do so under the *2007 Electric Utilities Act*.

<u>No Appeal of Decision that Line Loss Rule Was Unlawful</u>

No appeal was brought following the AUC's determinations in Phase I that the Line Loss Rule was unlawful. The ABCA considered this to mean that the AUC's finding that the rule was unlawful was accepted by all market participants. Therefore, the ABCA found that, as of April 2014, following the release of the AUC's review and variance decision:

(a) all market participants were aware that the Line Loss Rule was unlawful; and

(b) all market participants were aware that the unlawful Line Loss Rule had continued in effect since January of 2006.

<u>Asserted Grounds for Appeal</u>

The Applicants argued that the AUC erred in law and jurisdiction because it engaged in impermissible retroactive ratemaking. by finding that it had jurisdiction to adjust the line loss charges retroactively to January 1, 2006, the date the Line Loss Rule came into effect.

<u>Test for Permission to Appeal</u>

Section 29(1) of the *AUCA* provides that an appeal lies from a decision of the AUC on a question of jurisdiction or a question of law if a judge of the ABCA grants permission to appeal. The ABCA set out the following principles applicable to the applications for permission to appeal:

(a) the Applicants must show that the AUC's decision raised significant unanswered questions of law or regarding the AUC's jurisdiction;

(b) alternatively, the Applicants must show that the AUC erred in its application of settled legal principles or that it exceeded its jurisdiction;

(c) unless there was a question or problem of practical importance requiring an answer, permission to appeal ought not to be granted because there is no basis for an appeal;

(d) a question of law or jurisdiction is a question that raises doubt about a proposition of law or the taking of jurisdiction; and

(e) unless there existed a question of law or jurisdiction which had not already been authoritatively answered, no appeal lies.

No Question of Law or Jurisdiction on Which Appeal Should Be Granted

The ABCA held that the AUC's application of the rule against retroactive ratemaking was not so much a question of law but a question of whether a strict application of the rule in the circumstances of the case achieves sound utility regulation. The ABCA concluded that, therefore, the question raised by the Applicants did not raise questions of law or jurisdiction for which permission to appeal should be granted.

Standard of Review

The ABCA determined that the AUC's decision would be reviewable on the reasonableness standard, notwithstanding the AUC was deciding a jurisdictional question. The ABCA found that the AUC's decision did not turn on a question of law. It turned on the AUC's application of the law to the facts.

The ABCA found that, although the AUC was engaged in deciding a jurisdictional question, this did not automatically mean that its "decision raised a question or doubt about the AUC's jurisdiction."

AUC Decision Was Reasonable

The ABCA found that the AUC reasonably concluded that a retroactive or retrospective remedy was in the public interest.

The ABCA found the AUC decision was not only based on a thorough canvassing of public interest considerations, but also a decision which contained a defensible legal analysis of the issue of whether the AUC's adjustment of charges previously paid or avoided constituted impermissible retroactive ratemaking.

The ABCA found the AUC's interpretation of its legislation a reasonable response to look at providing some relief to those who had borne more than the cost that the *Electric Utilities Act* required them to bear, particularly given the mandate of the Board to ensure that the charges were compliant, not just going forward, but at all times.

Summary

The ABCA found that the AUC's decision that it could order a remedy or relief to correct the payment and receipt of unlawful line loss charges and credits did not raise questions of law or jurisdiction which required an appeal to the ABCA. Therefore, the ABCA dismissed the applications for permission to appeal.

Cymbaluk v TransAlta Corporation, 2018 ABCA 429

Permission to Appeal - Denied

In this decision, the Alberta Court of Appeal ("ABCA") considered an application by David Cymbaluk, Ferne Cymbaluk, and Philip Cymbaluk (the "Cymbaluks") for permission to appeal a decision of the AER dated September 7, 2018 (the "AER Decision"). The AER Decision addressed the obligations of TransAlta Corporation ("TransAlta") with respect to the sand, gravel, clay, and marl (the "Subsurface Materials") removed during the mining operation at TransAlta's Highvale Coal Mine.

The ABCA denied permission to appeal.

Background

TransAlta is the owner of the Highvale Coal Mine, a surface coal mine located approximately 75 kilometres west of Edmonton. The Cymbaluks resided on lands adjacent to the mine boundary and jointly owned a southeast quarter of section within the mine area (the "Lands").

Before TransAlta commenced mining on the Lands, it applied for a right of entry order under the *Surface Rights Act*, from the Surface Rights Board (the "SRB"). On November 8, 2005, the Board granted the order authorizing TransAlta to enter the Lands "for the removal of minerals and for or incidental to any mining operations and for the construction and operation of tanks, stations and structures for or incidental to such mining operations or the production of coal."

On November 23, 2006, the AER's predecessor granted TransAlta an approval under the *Environmental Protection and Enhancement Act* ("*EPEA*"), which authorized TransAlta to remove subsoil taken from the lands and substitute suitable spoil or overburden for the salvaged subsoil (the "2006 Approval"). The Cymbaluks received notice of the *EPEA* application but did not appeal the granting of the 2006 Approval. The 2006 Approval was valid for ten years.

On September 10, 2016, the AER renewed the 2006 Approval, permitting TransAlta to construct, operate, and reclaim the mine (the "2016 Approval").

The Cymbaluks expressed concerns regarding the reclamation and restoration plans for the project. They asserted that the clay that TransAlta removed from the lands during pre-mining operations was material that belonged to them and was taken. The AER found that the applicants did not demonstrate that they were "directly and adversely affected by the applications."

Both the 2006 Approval and 2016 Approval set out a number of terms and conditions for the construction, operation, and reclamation of the mine.

<u>The AER Decision</u>

The issues before the AER were:

(a) whether TransAlta had an obligation to return the Subsurface Materials; and

(b) whether the AER had the jurisdiction to address ownership rights over the Subsurface Materials claimed by the Cymbaluks.

The AER found that TransAlta was not required to return all Subsurface Materials that it removed. The AER found that TransAlta was authorized to substitute soil or overburden for the salvaged subsoil on the lands. The AER observed that TransAlta was required, under the 2006 Approval, 2016 Approval, and its Reclamation Plan, to return subsoil to a depth of one metre. Further, the AER observed that TransAlta could not reverse its past soil handling and disposition, which were undertaken in accordance with its 2006 Approval.

The AER held that it did not have jurisdiction to address the property right claim by the Cymbaluks in the Subsurface Materials. The AER stated its jurisdiction was "confined to regulating the operation, abandonment and reclamation of energy resource activities in accordance with the *Responsible Energy Development Act* ("*REDA*") and the applicable energy resource and specified enactments." The AER stated that if the applicants believed they suffered a loss of Subsurface Materials following reclamation, they may have recourse to the SRB or to the courts.

<u>Issues</u>

The Cymbaluks sought permission to appeal the AER Decision on the following grounds:

(a) whether the AER erred in concluding it did not have jurisdiction to address the applicants' property rights claim to the Subsurface Materials;

(b) whether the AER made a finding about TransAlta's proprietary claim to the Subsurface Materials, and if so, whether that was an error because it was inconsistent with its conclusion on jurisdiction; and

(c) whether, by referring to the 2006 Approval in its reasons, the AER breached procedural fairness because it referred to evidence that neither party put before it.

<u>Test for Permission to Appeal</u>

The ABCA set out that, under *REDA* section 45(1), permission to appeal may be granted on questions of law or jurisdiction only. When deciding whether to grant permission, the ABCA considers the following factors:

(a) Is the issue of general importance?

(b) Is the point raised of significance to the decision itself?

(c) Does the appeal have arguable merit?

(d) What standard of review is likely to be applied?

(e) Will the appeal unduly hinder the progress of the proceedings?

ABCA Findings

Did the AER Err in Concluding It Did Not Have Jurisdiction to Address the Applicants' Property Rights Claim to the Subsurface Materials?

The ABCA determined that while the jurisdiction of the AER to determine property rights is a question of law, it had no arguable merit, and permission to appeal on this ground was denied.

Did the AER Err by Making a Finding About Property Rights in Subsurface Materials Inconsistent with Its Conclusion on Jurisdiction?

The applicants sought permission to appeal the AER's finding that "TransAlta ... may use Subsurface Materials removed from [the land] for reclamation purposes on other parcels that form part of TransAlta's Highvale Mine." The applicants argued that this was a finding on property rights, and was therefore inconsistent with the AER's conclusion on jurisdiction.

The ABCA held there was no inconsistency. Accordingly, permission to appeal on this ground was denied. The ABCA found that the AER made rulings on how reclamation could occur. It did not address ownership rights or the implications that might arise if there was interference with ownership rights.

Did the Decision Violate Procedural Fairness by Referring to the 2006 Approval?

The ABCA found that the applicants were already aware of the relevant contents of the 2006 Approval and were not denied fairness.

Although procedural fairness is a question of law, the ABCA found that given that one part of the permission to appeal test asks whether the point raised is of significance to the decision itself, the circumstances did not warrant permission to appeal on this ground. The ABCA found this was not an issue of general importance. Whether in this case the AER should have considered the 2006 Approval was a matter of primary significance to the parties alone.

Summary

The ABCA denied the application for permission to appeal.

Blair v Alberta (Utilities Commission), 2018 ABCA 438

Permission to Appeal - Denied

In this decision, the ABCA considered an application by a number of landowners' (the "Applicants") for permission to appeal AUC Decision 22665-D01-2018 (the "AUC Decision"). In the AUC Decision, the AUC approved applications (the "Applications") by EDP Renewables SH Project GP Ltd. ("EDP") for approval of the Sharp Hills Wind Project (the "Project").

The ABCA denied permission to appeal, based on finding that the Applicants did not demonstrate a serious, arguable question of law or jurisdiction arising from the AUC Decision.

Background

The Project involved construction of 83 wind turbines and a substation in the New Brigden and Sedalia areas, in southeastern Alberta. The Applicants owned land near the Project and opposed its approval.

The Applicants opposed the Project in part because it would impact three private airstrips located near the Project area. In total, the Project would place 21 wind turbines within four kilometres of these airstrips. The AUC was "of the view that EDP has sited the project turbines at sufficient distances from the three airstrips to allow the three airstrips to be operated safely."

The AUC approved the Project and released the Decision on September 21, 2018.

Test for Leave to Appeal

Pursuant to section 29(1) of the *Alberta Utilities Commission Act*, an appeal lies from a decision or order of the AUC to the ABCA on a question of jurisdiction or law. To succeed, an applicant must demonstrate that the question of law or jurisdiction raises a "serious, arguable point." The ABCA considers the following factors in determining whether an applicant has satisfied this test:

(a) whether the point on appeal is of significance to the practice;

(b) whether the point raised is of significance to the action itself;

(c) whether the appeal is *prima facie* meritorious or, on the other hand, whether it is frivolous;

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

(e) the standard of appellate review that would be applied if leave were granted.

The ABCA referred to the to Supreme Court of Canada ("SCC")'s decision *ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission),* 2015 SCC 45, in which the SCC reiterated that to the extent an appeal turns on the AUC's interpretation of its home statute(s), a standard of reasonableness presumptively applies.

Grounds for Making the Application

The Applicants raised two issues in their application for permission to appeal:

(a) The AUC erred in law or jurisdiction by failing to observe the principles of procedural fairness by:

   (i) failing to provide the Applicants with adequate time to prepare for the public hearing and, in particular, by denying the Applicants' request for an adjournment of the public hearing;

   (ii) following a hearing process which provided the Applicants with no opportunity to test and challenge key evidence; and

   (iii) failing to critically assess the evidence given by the experts for EDP in light of their close ties to the wind energy industry.

(b) The AUC erred in law or jurisdiction by incorrectly and unreasonably interpreting documents published by Transport Canada (the "Transport Canada Documents"), and relying upon that incorrect and unreasonable interpretation in finding that the placement of turbines in proximity to airstrips was consistent with public safety and public interest.

Did the AUC Err in Law or Jurisdiction by Failing to Observe Procedural Fairness Principles?

The Applicants argued that the AUC's failure to observe the rules of procedural fairness raised a serious, arguable point of law. They asserted issues of procedural fairness clearly have significance to both the practice in general and the action itself.

Denial of Adjournment Request

The ABCA rejected the Applicants' argument that by denying their request for an adjournment of the public hearing, the AUC failed to provide the Applicants with adequate time to prepare for the hearing.

The ABCA concluded that no question of law or jurisdiction existed and accordingly denied permission to appeal on this ground.

The ABCA noted that the Applicants had ten days to prepare their expert witnesses before the commencement of the hearing. The ABCA found that there was no merit to the Applicant's submissions that the AUC's decision to grant merely a one-day adjournment was unfair.

Reliance on AEP's Referral Reports

The ABCA found the AUC's review of the evidence was "clearly within its purview". Accordingly, the ABCA found no question of law or jurisdiction existed and denied permission to appeal on this ground.

Although the Applicants were not entitled to cross-examine on AEP's Referral Reports at the hearing, the ABCA noted they were afforded the opportunity in advance of the hearing to submit written questions to AEP and to receive its response. Further, AEP's Referral Reports were based on evidence provided in many instances by EDP's expert witnesses, who were available for cross-examination at the hearing.

Reliance on EDP's Expert Witnesses

The ABCA found the substance of this ground was a complaint regarding the manner in which the evidence, and in particular the expert evidence, was dealt with and reviewed by the AUC. The ABCA found that no question of law or jurisdiction could be extricated from this exercise and accordingly permission to appeal on this ground was denied.

Did the AUC Err in Law or Jurisdiction by Incorrectly and Unreasonably Interpreting Documents Published by Transport Canada?

The ABCA found that the AUC did not unreasonably interpret the Transport Canada Documents. More importantly, there were no Transport Canada airport regulations that governed the Project. The ABCA confirmed that the use of lands outside of an unregistered aerodrome property was governed by provincial and municipal governments, not Transport Canada.

The ABCA found the AUC's conclusion that the placement of the turbines did not create a risk to public safety was a question of mixed fact and law. As a result, the Applicants did not show there was an issue of law or jurisdiction arising from the AUC's interpretation of the Transport Canada Documents.

Summary

Based on finding that the Applicants did not demonstrate that the questions of law or jurisdiction raised a serious, arguable point, the ABCA denied permission to appeal.

Dorin v EPCOR Distribution and Transmission Inc., 2018 ABCA 427

Permission to Appeal - Granted

In this decision, the Alberta Court of Appeal ("ABCA") considered Mark Dorin's application for permission to appeal AUC Decision 23128-D01-2018 ("the Decision"). In the Decision, the AUC concluded t was in the public interest to approve an application from EPCOR Distribution and Transmission Inc. ("EPCOR") to construct and operate an electrical substation (the "Substation") and associated transmission and communications infrastructure (the "Project") pursuant to section 17 of the *Alberta Utilities Commission Act* ("*AUCA*").

The ABCA granted permission to appeal (in part) on the following question:

- What was the effect, if any, of the absence of written consent by the Minister of Infrastructure given prior to the making of the Decision by the AUC, on EPCOR's ability to proceed to have the Substation built and made operational?

Background

EPCOR hoped to build the Substation to serve the growing demand for electricity in rapidly-expanding southwest Edmonton. Mr. Dorin held an option to purchase lands adjacent to the transportation and utility corridor on which the Substation was proposed to be built. He did not challenge the identified need for the Substation but rather the specific sites upon which it was approved to be built, given certain alleged risks of leaks from oil and gas facilities, comprised of wells, pipelines and a tank battery located near those sites.

The AUC granted EPCOR approval to build the Substation on either of two sites, subject to subsequently obtaining written approval from the Alberta Minister of Infrastructure.

Test for Leave to Appeal

Section 29 of the *AUCA* provides "…an appeal lies from a decision or order of the Commission to the Court of Appeal on a question of jurisdiction or on a question of law." The general test to be applied on an application for permission to appeal is that the question of jurisdiction or law in issue raises a "serious, arguable point."

In determining whether Mr. Dorin's appeal raised a "serious, arguable point," the ABCA considered:

(a) whether the point on appeal was of significance to the practice;

(b) whether the point raised was of significance to the action itself;

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

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

(e) the standard of appellate review that would be applied if leave were granted.

AUC Approval Without Having Received Ministerial Consent

One ground for appeal was raised on the basis that section 4(2) of the *Edmonton Restricted Development Regulations* (the "*Regulation*") required the AUC to have received Ministerial consent before holding the hearing which produced the Decision under appeal.

The ABCA found that Mr. Dorin raised a "serious arguable point" on his appeal based on the following:

(a) the point was of significance to the procedure to be followed by the AUC in this and in future cases;

(b) if the ultimate interpretation resulted in a conclusion that the AUC acted prematurely it would be of significance to the approval process for the Substation;

(c) the appeal had merit to the extent that the basis for it could be articulated and there was no authority directly resolving the interpretation of section 4(2) of the *Regulation.* The plain wording of the section left open the argument that the only reasonable or correct interpretation of is that Ministerial consent was required before the AUC held its hearings or issued the Decision; and

(d) nothing indicated that the appeal would disproportionately hinder the progress of the approval process even if ultimately unsuccessful.

The ABCA found that these observations existed no matter which standard of review must be exercised in relation to the Decision.

No authority was produced that directly addressed the interpretation of section 4(2) of the *Regulation* to resolve this point.

Mr. Dorin raised a variety of other issues in his oral and written argument. None of his related concerns rose to the level of being serious arguable points.

Summary

The ABCA granted permission to appeal in relation to a single issue, restated, as follows:

- What was the effect, if any, of the absence of written consent by the Minister of Infrastructure given prior to the making of the Decision by the AUC, on EPCOR's ability to proceed to have the Substation built and made operational?

ALBERTA ENERGY REGULATOR

Request for Regulatory Appeal by Elizabeth Métis Settlement (AER Regulatory Appeal Nos: 1913250 and 1913252)

Request for Regulatory Appeal - Granted

In this decision, the AER considered the Elizabeth Métis Settlement ("EMS")'s request for a regulatory appeal of the AER's decisions to issue Approval Nos.: 73534-01-02 under the *Environmental Protection and Enhancement Act* ("*EPEA*") (the "*EPEA* Approval") and 8558MM under the *Oil Sands Conservation Act* ("*OSCA*") (the "*OSCA* Approval) (collectively, the "Approvals") to Imperial Oil Resources Ltd. ("Imperial").

The AER granted the request for regulatory appeal, finding that EMS was an eligible person under section 38 of the *Responsible Energy Development Act* ("*REDA*").

Background

The Approvals related to an expansion of Imperial's Cold Lake thermal oil sands in-situ recovery project. The expansion project involved construction of a central processing facility, solvent-assisted steam assisted gravity drainage ("SAGD"), and other related infrastructure to connect wells to the central processing facility and pipeline connections (the "Expansion Project").

Legal Framework

Section 38 of *REDA* provides that an eligible person may request a regulatory appeal of an appealable decision by filing a request for regulatory appeal.

The test has three components:

(a) the decision must be an appealable decision;

(b) the requester must be an eligible person; and

(c) the request must be filed in accordance with the rules.

Appealable Decision

The AER found that the decision to issue the *EPEA* Approval and the decision to issue the *OSCA* Approval were both appealable decisions under *REDA*.

The AER found that the decision to issue the *OSCA* Approval was an appealable decision under *REDA* section 36(a)(iv), since it was made under the *OSCA,* "an energy resource enactment," and was made without a hearing.

The AER found that the decision to issue the *EPEA* Approval was an appealable decision under *REDA* section 36(a)(i), since it was a decision for which a person would otherwise be entitled to submit a notice of appeal under section 91(1) of the *EPEA* and was made without a hearing.

Eligible Person

Under *REDA* section 36(b)(ii), for energy resource enactment decisions, an eligible person is a person who is directly and adversely affected by such a decision made without a hearing. For an *EPEA* amendment approval decision, an eligible person is defined, under *REDA* section 36(b)(i), as including a person who previously submitted a statement of concern and who is directly affected by the decision

The AER found that EMS might be directly and adversely affected by the Approvals, and was, therefore, an eligible person, based on the following findings:

(a) EMS had demonstrated in its Traditional Land Use Study that there was overlap between the Expansion Project area and the use of parts of the area by certain EMS members for hunting, gathering, trapping, and fishing. These activities by its members were ongoing and continuous.

(b) The Environmental Impact Assessment for the expansion project confirmed that it would affect large areas of high and good quality animal habitat, including habitat for some species specifically identified by EMS as species which they hunt in the Expansion Project area.

The AER explained its approach to assessing adversely and directly affected as follows:

- Where the development or activity in question has not yet occurred, and the actual impacts are not yet known the phrase "is directly and adversely affected" or "is directly affected" does not require certain proof that the person will be affected.

- What is required, is reliable information in the regulatory appeal request that demonstrates a "reasonable potential or probability" that the person asserting the impact will be affected.

The AER cited from the Alberta Court of Appeal ("ABCA") decision *Dene Tha' First Nation v. Alberta* ("*Dene*"), in which the ABCA provided guidance on what an aboriginal group must do to meet the factual part of the directly and adversely affected test. In *Dene*, the ABCA held that a person or group that asserts that he or she may be directly and adversely affected by the AER's decision on an application must demonstrate a degree of location or connection with that application, or its effects, in order to bring himself or herself within the bounds of the legislative provision.

The AER found that EMS had satisfied this test

Stay

The AER decided to temporarily stay the Approvals, pending its final decision on the stay request. The AER directed EMS and Imperial to file submissions regarding the stay request before it makes a decision on the stay.

Under *REDA* section 39(2), the AER may, on the request of a party to a regulatory appeal, stay the appealable decision.

The AER determined that a short-duration, interim stay of the Approvals was the best mechanism to ensure fairness and certainty of the stay decision timing for both parties. The AER found that a short-term stay pending final determination of the full stay request would not prejudice Imperial, and would ensure that EMS was not prejudiced by Imperial commencing construction and operations.

Summary

The AER granted the requests for regulatory appeals.

The AER decided to temporarily stay the Approvals, pending final determination of the full stay request.

AER Bulletin 2018-35: Government of Alberta Curtails Production

Crude Oil - Crude Bitumen

On December 2, 2018, the Government of Alberta ("GoA") announced short-term reductions in crude oil and crude bitumen production effective January 1, 2019.

On December 3, 2018, the GoA released *Curtailment Rules*, regulations made under the *Oil and Gas Conservation Act, Oil Sands Conservation Act* and the *Responsible Energy Development Act*, setting out the framework for how these reductions would be made. The *Curtailment Rules* enable the limiting of crude oil and crude bitumen production in Alberta according to the prescribed formula.

The AER contacted operators subject to curtailment requirements on December 6, 2018. Companies that did not receive a ministerial order are not required to limit production at this time.

The AER stated that it would be establishing a panel to hear stakeholder concerns related to these curtailment measures and was working with the GoA to finalize panel details.

AER Bulletin 2018-38: Change in Notification of Primary Recovery Scheme Applications for Well Spacing Within the Oil Sands Area

Notification - Primary Recovery Scheme

Effective immediately, applicants are no longer required to notify landowners and occupants of primary recovery scheme applications for well spacing within the oil sands areas. These applications are for an increase in the number of subsurface locations to recover heavy oil or bitumen from a specified formation or deposit within a particular area (drilling spacing unit). They do not include a request for authorization of surface activities.

Applicants must still notify landowners and occupants, under *Directive 056: Energy Development Applications and Schedules*, of any applications for surface activities, such as the construction and operation of pipelines, wells, and other surface facilities. Public notice of all AER applications, including primary recovery scheme applications, will continue to be provided on the AER website.

AER Bulletin 2018-40: Production Curtailment Issues Panel Established

Curtailment Rules - Crude Oil - Crude Bitumen

The AER announced in this bulletin that it had established a production curtailment issues panel. The panel is seeking feedback on the *Curtailment Rules* from all operators. Written submissions will be reviewed and considered and advice provided to the president and chief executive officer of the AER and the Minister of Energy.

AER Bulletin 2018-41: The Approach to Administering the Remediation Regulation

Remediation

On June 1, 2018, the Government of Alberta issued the *Remediation Certificate Amendment Regulation* ("*Remediation Regulation"*), which came into effect on January 1, 2019. This regulation sets out requirements for reporting new information and remedial measures regarding substance releases. The regulation also enhances the AER's remediation certificate program.

Commencing in 2019, the AER will be taking a risk-based approach to administering the *Remediation Regulation* for its upstream jurisdiction. The AER explained that this approach will include streamlined reporting and intended to support and enable area-based closure in Alberta.

The AER confirmed that it continues to require that all substance releases that may cause, are causing, or have caused an adverse effect, be remediated or managed in accordance with applicable legislation.

ALBERTA UTILITIES COMMISSION

ATCO Pipelines Decision on Preliminary Question - Application for Review of Decision 23537-D01-2018 (Errata) Compliance Application to Decision 22986-D01-2018 (AUC Decision 23953-D01-2018)

Weld Assessment and Repair Program - Review and Variance

In this decision, the AUC granted ATCO Pipeline's application requesting a review and variance of AUC Decision 23537-D01-2018 (Errata) (the "Decision").

The review application concerned the AUC's disallowance in the Decision of all incremental weld repair costs associated with ATCO's weld assessment and repair program ("WARP").

Background

ATCO Pipelines filed its 2017-2018 general rate application ("GRA") on September 22, 2016, considered by the AUC in Proceeding 22011. As part of its GRA, ATCO sought to incorporate into its 2017 and 2018 revenue requirements, costs associated with the WARP; specifically, the costs to re-inspect several prefabricated welds and repair any defective work. ATCO Pipelines outlined deficiencies concerning radiographic inspections of its prefabricated welds.

In Decision 22011-D01-2017 (the "GRA Decision"), the AUC deferred its decision on the WARP costs and directed ATCO Pipelines to file additional information in a compliance filing.

In Decision 22986-D01-2018 (the "First Compliance Decision"), the AUC denied 100 percent of the WARP re-inspection. The AUC held that additional information was required before a conclusion could be reached on the reasonableness of ATCO Pipelines' repair costs. The AUC directed ATCO Pipelines to provide additional information regarding the WARP repair costs in a further compliance filing.

ATCO Pipelines requested a review and variance of the AUC's disallowance of the WARP re-inspection costs in the First Compliance Decision. On September 27, 2018, the AUC issued Decision 23539-D01-2018 (the "WARP Re-inspection Costs R&V Decision"), in which it granted the first stage of ATCO's review application. The AUC granted a review based on the hearing panel's misplaced reliance on intervener argument as the basis for what actions ATCO should have taken prior to discovering the deficiencies. The review panel found that this constituted an error of fact, law or jurisdiction apparent on the face of the decision that could lead the AUC to materially varying or rescinding that decision.

Decision Subject to Review Application

In the Decision, the AUC found it unreasonable to permit ATCO Pipelines to recover re-inspection costs from customers when it could pursue recovery of these costs through litigation from those responsible (the involved radiographic inspection companies and technicians). The AUC found that ATCO Pipelines should recover the costs from the involved radiographic companies and technicians rather than recover costs from customers and then credit customers for any litigation proceeds. The AUC considered that ratepayers should not be responsible for any incremental repair costs arising from the improper inspections.

Legislative Framework

ATCO Pipelines filed the present application for review of the AUC's denial of 100 percent of the incremental WARP repair costs in the Decision.

The review application requested a review and variance of the Decision, pursuant to section 10 of the *Alberta Utilities Commission Act* ("*AUCA*") and *Rule 016: Review of Commission Decisions* ("Rule 016").

The AUC's authority to review its own decisions is discretionary and is found in section 10 of the *AUCA*. Rule 016 sets out the process for considering an application for review. A person who is directly and adversely affected by a decision may file an application for review within 60 days of the issuance of the decision, pursuant to section 3(3) of Rule 016. ATCO Pipelines filed its review application within the required period.

Two-stage Review Process

The review process typically has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. This is sometimes referred to as the "preliminary question." If the review panel decides that there are grounds to review the decision, it proceeds 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.

In this decision, the review panel decided the preliminary question for the review application.

Grounds for Review

Section 4(d) of *Rule 016* requires an applicant to set out the grounds it is relying on in support of its application for a review. These grounds may include an error of fact, law or jurisdiction made by the hearing panel (subsection 4(d)(i)). ATCO's review application alleged such errors.

ATCO Pipelines submitted that the review application should be granted on the grounds that the error found by the AUC in the WARP Re-inspection R&V Decision applied equally to the disallowed weld repair costs and the Decision. It argued that the AUC's disallowance of weld repair costs associated with improper inspections was arbitrary and counter to the AUC's stated "periodic review and monitoring" standard.

Review Panel Findings

The AUC review panel granted the review application, holding that ATCO Pipelines demonstrated an error of fact, law or jurisdiction that was apparent on the face of the Decision that could lead the AUC to materially vary or rescind the Decision. This conclusion was supported by the following findings:

(a) the original finding that "ratepayers should not be responsible for any incremental repair costs arising from the improper inspections" was premised on the AUC's disallowance of re-inspection costs in the First Compliance Decision; and

(c) as the Decision was premised on findings that were subject to review, the review panel was satisfied that the Decision should be reviewed as well.

Summary

In answering the preliminary question on ATCO Pipelines' review application, the review panel found that ATCO Pipelines demonstrated that an error of fact, law or jurisdiction existed on the face of the Decision that could lead the AUC to materially vary or rescind the Decision. Accordingly, the AUC granted the first stage review.

The AUC ordered that the second stage review processes for each of the Decision and the First Compliance Decision would be conjoined in the interests of regulatory efficiency.

ATCO Electric Ltd. 2017 Performance-Based Regulation Capital Tracker True-Up (AUC Decision 23739-D01-2018)

Performance-Based Regulation - Electricity

In this decision, the AUC approved ATCO Electric Ltd. ("ATCO Electric")'s 2017 K factor true-up collection amount of $8.9 million to be collected from customers in its 2019 Performance-Based Regulation ("PBR") annual rates.

Overview of PBR Capital Tracker Mechanism

The PBR framework was approved in AUC Decision 2012-237 for 2013 to 2017 PBR plans. The PBR framework provides a formula mechanism for the annual adjustment of rates over a five-year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs, less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs under a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

Certain items may be adjusted for necessary capital expenditures ("K Factor"), flow through costs ("Y Factor"), or exogenous material events for which the company has no other reasonable cost control or recovery mechanism in its PBR plan ("Z Factor").

The AUC approved a rate adjustment mechanism to fund certain capital-related costs, referred to as the capital tracker. The capital tracker provides a supplemental funding mechanism for approved amounts to be collected from ratepayers by way of a K Factor adjustment to the annual PBR rate setting formula.

Projects or programs are eligible for capital tracker treatment if they meet the following three criteria:

(a) the project must be outside the normal course of on-going operations ("Criterion 1");

(b) ordinarily, the project must be for replacement of existing capital assets or the project must be required by an external party ("Criterion 2"); and

(c) the project must have a material effect on the company's finances ("Criterion 3").

Criterion 1: Project Assessment and Accounting Test

Criterion 1 requires a two-stage assessment of each project or program for which capital tracker treatment is requested.

At the first stage (project assessment), an applicant must demonstrate that:

(a) the project is required to provide utility service at adequate levels; and, if so,

(b) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project are reasonable.

At the second stage, an applicant must demonstrate the absence of double-counting (the "Accounting Test"). The purpose of the Accounting Test is to determine whether a project or program proposed for capital tracker treatment is outside the normal course of the company's ongoing operations. This is achieved by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program.

Criterion 2: Insufficient Customer Contributions and Incremental Revenue

With respect to Criterion 2, a growth-related project will generally qualify where an applicant demonstrates that customer contributions and incremental revenues are insufficient to offset the project's cost.

Criterion 3: Materiality Test

To assess whether a proposed capital tracker has a material effect on a company's finances, an applicant must satisfy the two-part Criterion 3 materiality threshold (the "Criterion 3 Materiality Test"). Namely, that:

(a) each individual project affects the revenue requirement by four basis points; and

(b) on an aggregate level, all proposed capital trackers must have a total impact on the revenue requirement of 40 basis points.

<u>AUC Process for Reviewing the ATCO Electric 2017 Capital Tracker True-Up Application</u>

For 2017 capital tracker true-up applications, the AUC assessed the scope, level, and timing of each project or program for prudence, and whether the actual costs on the project or program were prudently incurred. The AUC did not undertake a reassessment of the need under the project assessment component of Criterion 1 for projects the AUC previously confirmed the need for in prior capital tracker.

For programs or projects previously approved under the Criterion 2 requirements, the AUC did not undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program had changed.

The AUC also conducted an assessment of the 2017 capital tracker projects and programs with respect to the accounting test under Criterion 1 and materiality test under Criterion 3.

To the extent the AUC previously approved the grouping of projects for capital tracker purposes, the AUC did not re-evaluate those groupings in this decision.

<u>Overview of the ATCO Electric Projects Included in the 2017 Capital Tracker True-Up Application</u>

The projects included in ATCO Electric's 2017 capital tracker true-up and the variance from the approved forecast, resulting in proposed K Factor true-up adjustment for 2017, were as follows:

(a) information technology related;

(b) tools and instruments;

(c) transportation equipment;

(d) overhead line rebuilds, replacements, and life extension;

(e) wood pole replacements and life extension;

(f) reliability;

(g) wildfire risk reduction;

(h) underground rebuilds, replacements, and life extension;

(i) distribution to transmission contributions;

(j) buildings structures and leasehold improvements;

(k) third-party driven relocations;

(l) new extensions; and

(m) distribution automation,

(the "Projects").

<u>Grouping of Projects for Capital Tracker Purposes</u>

The AUC approved ATCO Electric's grouping of the Projects proposed in its application. The AUC found that ATCO Electric's capital tracker schedules, which include its non-capital tracker projects, complied with the AUC's previous directions.

<u>Criterion 1</u>

The AUC found that the actual 2017 costs for each of the programs or projects were prudent. This was based on the evidence provided by ATCO Electric supporting the costs, the associated procurement, and construction practices and ATCO Electric's explanation of the differences between the approved forecast and actual costs.

Project Assessment: Distribution to Transmission Contributions

The Distribution to Transmission Contributions Program consisted of the annual contributions that ATCO Electric was required to make for transmission projects that directly relate to transmission system access in its distribution service territory.

The AUC found that ATCO Electric's 2017 actual capital additions associated with the Distribution to Transmission Contributions Program were prudent. The Distribution to Transmission Contributions Program consisted of the annual contributions that ATCO Electric is required to make for transmission projects that directly relate to transmission system access in its distribution service territory.

The 2017 approved forecast capital additions for this program were $36.2 million and the actual 2017 capital additions were $3.6 million, resulting in a $32.6 million variance below forecast. The AUC found ATCO Electric's 2017 actual capital additions associated with the Distribution to Transmission Contributions to be consistent with the variance explanations provided and consistent with the scope. The 2017 approved forecast capital additions for this program were $36.2 million and the actual 2017 capital additions were $3.6 million, resulting in a $32.6 million variance below forecast. The AUC accepted ATCO Electric's explanation that cost variations were generally attributed to final construction costs, finalized customer contribution decision ("CCD") calculations, and in-service date variations from forecast.

Project Assessment: Distribution Automation Program

The Distribution Automation Program was an ongoing multi-year program, which consisted of a number of small projects related to two interdependent components: the installation of field Supervisory Control and Data Acquisition ("SCADA") infrastructure; and the development and integration of control centre technology and enterprise systems.

The AUC found that the Distribution Automation Program satisfied the project assessment requirement of Criterion 1 and, therefore, the AUC approved the Distribution Automation Program capital costs as proposed for 2017 capital tracker treatment.

In the application, ATCO Electric provided a business case, engineering studies and actual results realized in 2013 to 2017 for the Distribution Automation Program.

Accounting Test Under Criterion 1

The AUC found that ATCO Electric's programs or projects proposed for capital tracker treatment in 2017 on an actual basis satisfied the project assessment requirement of Criterion 1, based on the following:

(a) ATCO Electric used the correct values for its weighted average cost of capital ("WACC"), I-X, and Q assumptions used in the first component of the accounting test;

(b) ATCO Electric's accounting test demonstrated that all or a portion of the actual expenditures for a capital project were outside the normal course of the company's ongoing operations.

Criterion 2

ATCO Electric confirmed that there were no changes to the drivers of any of its previously approved capital tracker programs

Distribution Automation Program

With respect to Criterion 2, the AUC clarified in Decision 2013-435 that certain projects proposed for capital tracker treatment that did not fall into any of the growth-related, asset replacement or external-party-related categories might also satisfy Criterion 2 in certain circumstances.

The Distribution Automation Program was an example of a capital tracker project that did not fit into any of the three Criterion 2 categories.

The AUC found that the Distribution Automation Program projects were required to provide utility service at adequate levels and to maintain safe operation of ATCO Electric's distribution system. Furthermore, the program was not adequately funded under the I-X mechanism in 2017. Therefore, the AUC found that the Distribution Automation Program satisfied the requirements of Criterion 2.

Criterion 3

The AUC found that ATCO Electric applied the Criterion 3 Materiality Test correctly for the purposes of the 2017 capital tracker true-up, based on the projects and assumptions included in the application. The AUC found that each of ATCO Electric's proposed capital tracker programs for 2017 exceeded the materiality thresholds and, therefore, satisfied Criterion 3.

2017 True-Up K Factor Calculations

In Decision 21516-D01-2016, the AUC approved a 2017 forecast K Factor of $62.6 million to be recovered from ATCO Electric's customers on an interim basis. As part of the 2017 capital tracker true-up, ATCO Electric calculated its actual 2017 K Factor to be $71.5 million, resulting in a proposed 2017 K Factor true-up adjustment of $8.9 million, to be collected from customers. ATCO Electric included this amount in its 2019 PBR annual rates application.

The AUC found that ATCO Electric's methodology in determining the 2017 K Factor true-up amount was consistent with the requirements set out in Decision 2012-237 and Decision 2013-435. The AUC approved the 2017 K Factor true-up collection amount of $8.9 million. The AUC further approved the collection of this amount through ATCO Electric's 2019 PBR annual rates.

Summary

The AUC approved ATCO Electric's 2017 K Factor true-up collection amount of $8.9 million to be collected from customers in its 2019 PBR annual rates.

AltaGas Utilities Inc. 2017 Capital Tracker True-Up Application (AUC Decision 23623-D01-2018)

Performance Based Regulation

In this decision, the AUC made a determination regarding AltaGas Utilities Inc. ("AltaGas")'s 2017 capital tracker true-up application.

Overview of PBR Capital Tracker Mechanism

The PBR framework was approved in AUC Decision 2012-237 for 2013 to 2017 PBR plans. The PBR framework provides a formula mechanism for the annual adjustment of rates over a five-year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs, less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs under a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

Certain items may be adjusted for necessary capital expenditures ("K Factor"), flow through costs ("Y

Factor”), or exogenous material events for which the company has no other reasonable cost control or recovery mechanism in its PBR plan (“Z Factor”).

The AUC approved a rate adjustment mechanism to fund certain capital-related costs, referred to as the capital tracker. The capital tracker provides a supplemental funding mechanism for approved amounts to be collected from ratepayers by way of a K Factor adjustment to the annual PBR rate setting formula.

Projects or programs are eligible for capital tracker treatment if they meet the following three criteria:

(a) the project must be outside the normal course of on-going operations (“Criterion 1”);

(b) ordinarily, the project must be for replacement of existing capital assets or the project must be required by an external party (“Criterion 2”); and

(c) the project must have a material effect on the company’s finances (“Criterion 3”).

Criterion 1: Project Assessment and Accounting Test

Criterion 1 requires a two-stage assessment of each project or program for which capital tracker treatment is requested.

At the first stage (project assessment), an applicant must demonstrate that:

(a) the project is required to provide utility service at adequate levels; and, if so,

(b) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project are reasonable.

At the second stage, an applicant must demonstrate the absence of double-counting (the “Accounting Test”). The purpose of the Accounting Test is to determine whether a project or program proposed for capital tracker treatment is outside the normal course of the company’s ongoing operations. This is achieved by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program.

Criterion 2: Insufficient Customer Contributions and Incremental Revenue

With respect to Criterion 2, a growth-related project will generally qualify where an applicant demonstrates that customer contributions and incremental revenues are insufficient to offset the project’s cost.

Criterion 3: Materiality Test

To assess whether a proposed capital tracker has a material effect on a company’s finances, an applicant must satisfy the two-part Criterion 3 materiality threshold (the “Criterion 3 Materiality Test”). Namely, that:

(a) each individual project affects the revenue requirement by four basis points; and

(b) on an aggregate level, all proposed capital trackers must have a total impact on the revenue requirement of 40 basis points.

<u>AUC Process for Reviewing the 2017 Capital Tracker True-Up Application</u>

For 2017 capital tracker true-up applications, the AUC assessed the scope, level, and timing of each project or program for prudence, and whether the actual costs on the project or program were prudently incurred. The AUC did not undertake a reassessment of the need under the project assessment component of Criterion 1 for projects the AUC previously confirmed the need for in prior capital tracker.

For programs or projects previously approved under the Criterion 2 requirements, the AUC did not undertake a reassessment of the project or program against the Criterion 2 requirements unless the driver for the project or program had changed.

The AUC also conducted an assessment of the 2017 capital tracker projects and programs with respect to the accounting test under Criterion 1 and materiality test under Criterion 3.

To the extent the AUC previously approved the grouping of projects for capital tracker purposes, the AUC did not re-evaluate those groupings in this decision.

Materiality Threshold for Project or Program Variance Explanations

Based on AltaGas' most recent Rule 005: *Annual Reporting Requirements of Financial and Operational Results* filing, the AUC agreed that AltaGas fit within the $100 million to $500 million rate base category. AltaGas provided variance explanations as follows:

(a) for cost differences, where the variance for the actual total costs at the individual project is plus or minus $500,000; or greater than or equal to plus or minus 10 percent and a dollar amount greater than or equal to plus or minus $125,000 of the approved amount;

(b) for non-financial data, such as units/volume differences, where the variance for actual length of pipe at the individual project level is greater than or equal to plus or minus 10 percent of the approved amount; and

(c) explanations for differences in overhead rates for individual projects are provided where variances on an individual project are greater than plus or minus 0.5 percent, and plus or minus $10,000.

The AUC confirmed that the cost and non-financial variance explanation thresholds that AltaGas provided in the application were consistent with the Rule 005 thresholds.

The AUC found AltaGas' variance explanation threshold definition, including assessment at the project level rather than account line level, subject to significant variances at the account line level, to be reasonable.

Summary of Programs Included in the 2017 Capital Tracker True-Up

The table below sets out the programs included in AltaGas' 2017 capital tracker true-up application. The K factor true-up amounts are equal to the variance between the 2017 approved forecast K factor amounts and the 2017 actual K factor.

2017 K Factor True-Up and Adjustments

Program name	2017 approved forecast K factor	2017 actual K factor	K factor true-up
	($)		
Pipeline Replacement	6,703,659	6,108,230	(595,429)
Station Refurbishment	1,165,421	1,228,962	63,541
Gas Supply	428,124	344,751	(83,373)
	8,297,204	**7,681,943**	**(615,261)**
Carrying costs			(28,914)
2017 K factor total			**(644,176)**

Pipeline Replacement Program

The Pipeline Replacement Program is a multi-year program that provides for the replacement of three types of pipe: pre-1957 steel pipe, polyvinylchloride ("PVC") pipe, and non-certified and interim-certified polyethylene ("PE") (collectively referred to as "non-certified PE") pipe.

Station Refurbishment Program

The Station Refurbishment Program is also a multi-year program that provides for partial, through to complete, replacement of a particular station.

Gas Supply Program

The Gas Supply Program is also a multi-year program that ensures safe, continuous gas supply to customers.

Grouping of Projects for Capital Tracker Purposes

AltaGas used the same approach to grouping that was previously approved by the AUC for its three programs.

The AUC did not re-evaluate these groupings in this decision. The AUC found that AltaGas' description of the nature, scope, and timing of non-capital tracker projects complied with the AUC's previous direction.

Assessment of Individual Projects Within Programs Under Criterion 1

For each project, the AUC assessed whether the actual scope, level, timing, and costs of the previously approved capital tracker project or programs was prudent. The AUC also evaluated whether, for each project or program, AltaGas provided business cases, engineering studies, cost-related information, and related evidence and argument to demonstrate compliance with each of the project assessment minimum filing requirements.

The AUC found that:

(a) AltaGas' 2017 actual capital additions associated with each of the projects was consistent with the scope, level, and timing of the work outlined in the business case approved in Decision 20522-D02-2016;

(b) the actual scope, level, timing, and costs of the work undertaken in 2017 were prudent; and

(c) accordingly, the pre-1957 steel, PVC, and non-certified PE pipe replacement programs and each of the associated projects approved on a forecast basis in Decision 20522-D02-2016, satisfied the project assessment requirement of Criterion 1 for 2017.

Pipeline Replacement Program

The Pipeline Replacement Program provided for the replacement of three types of pipe: pre-1957 steel pipe; PVC pipe; and non-certified PE pipe.

In Decision 20552-D02-2016, the AUC approved the need on a forecast basis for each of the pre-1957 steel, PVC and non-certified PE pipe replacement projects for purposes of capital tracker treatment in 2016 and 2017. The AUC also determined that the proposed scope, level, timing and forecast costs for the approved projects and programs were reasonable.

The AUC found no evidence to indicate that any of the pre-1957 steel, PVC and non-certified PE pipeline replacement projects were not required in 2017.

Pipeline Replacement Program Trailing Costs

The AUC approved the inclusion of AltaGas' trailing costs as part of the project total costs for the purposes of the K factor calculation and found they were prudently incurred.

The application included trailing costs incurred in 2014, 2015, and 2016 associated with several pipeline replacement capital tracker projects previously approved on a forecast basis by the AUC in prior capital tracker decisions.

<u>Accounting Test Under Criterion 1</u>

The accounting test under Criterion 1 determines whether a project or program proposed for capital tracker treatment is outside the normal course of the company's ongoing operations. The accounting test is satisfied by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project.

The AUC found AltaGas' schedules, that made up its accounting test analysis for the purposes of the 2017 capital tracker true-up, were reasonable and consistent with the accounting test methodology approved in Decision 2013-435. The AUC verified AltaGas' weighted average cost of capital ("WACC"), I-X and Q value assumptions used in the first component of the accounting test, and found that AltaGas used the correct values. The AUC found AltaGas' 2017 actual WACC of 6.122 percent used in the second component of its accounting test, based on the 2017 actual cost of debt of 4.470 percent, as well as the approved equity thickness of 41 percent and the approved return on equity of 8.5 percent from Decision 20622-D01-2016, were reasonable.

The AUC was satisfied that AltaGas' accounting test model demonstrated that all of the actual expenditures for a capital project were, or a portion was, outside the normal course of the company's ongoing operations, as required to satisfy the accounting test component of Criterion 1.

The AUC found that AltaGas' programs or projects proposed for capital tracker treatment in 2017 on an actual basis satisfied the project assessment requirement of Criterion 1.

<u>Criterion 2</u>

Since AltaGas' 2017 capital tracker true-up had not changed since the AUC undertook and approved proposed capital tracker projects and programs against the Criterion 2 requirements in Decision 20522-D02-2016, there was no need to undertake a reassessment of these programs or projects against the Criterion 2 requirements.

<u>Criterion 3</u>

The AUC found that AltaGas interpreted and applied the Criterion 3 two-tiered materiality test correctly for the purposes of its 2017 capital tracker true-up, based on the projects and assumptions included in the application. The AUC found that each of AltaGas' proposed capital tracker programs for 2017 exceeded the materiality thresholds, and therefore satisfied Criterion 3.

Summary

The AUC approved the 2017 K factor true-up amount of $644,176. The AUC further approved the refund of this amount through AltaGas' 2019 annual PBR rates.

AUC Bulletin 2018-17: Electric Distribution System Inquiry

Electricity - Regulatory Framework

In this bulletin, the AUC indicated it was opening an inquiry into Alberta's changing electric distribution system. The purpose of the inquiry is to map out the key issues related to the future of the electric distribution grid and to aid in developing the necessary regulatory framework to accommodate the evolution of the electric system.

In general, the AUC intends for the inquiry to help answer three fundamental questions:

(a) How will technology affect the grid and incumbent electric distribution utilities; and how quickly?

(b) Where alternative approaches to providing electrical service develop, how will the incumbent electric distribution utilities be expected to respond and what services should be subject to regulation?

(c) How should the rate structures of the distribution utilities be modified to ensure that price signals encourage electric distribution utilities, consumers, producers, prosumers and alternative technology providers to use the grid and related resources in an efficient and cost-effective way?

Interested parties can provide comments in the AUC's eFiling System under Proceeding 24116 by January 18, 2019.

AUC Bulletin 2018-18: Standardized Post-Approval Monitoring Requirements for Wind and Solar Power Plants

Wind - Solar - Post-Approval Requirements

In this bulletin, the AUC stated that it is considering enacting a rule establishing standard post-approval monitoring requirements for wind and solar power plants. Although these requirements would apply to all such projects approved by the AUC, the AUC would retain the discretion to supplement, omit, or modify these requirements on a case-by-case basis in a decision report. In the AUC's view, the establishment of standard post-approval monitoring requirements would improve consistency of monitoring obligations for approved wind and solar power plants and would add certainty to the regulatory process.

The AUC invited stakeholders to provide written feedback, comments, and suggestions on standardizing post-approval monitoring requirements by January 28, 2019.

AUC Bulletin 2018-20: Specified Penalties for Contraventions of AUC Rules

AUC Rules - Amendments

Following a rule review and rule development process on December 11, 2018, the AUC approved Rule 032: *Specified Penalties for Contravention of AUC Rules* ("Rule 032") and amendments to Rule 021: *Settlement System Code Rules* ("Rule 021"), Rule 028: *Natural Gas Settlement System Code Rules* ("Rule 028") and Rule 003: *Service Standards for Energy Service Providers* ("Rule 003") (Formerly titled: *Service Quality and Reliability Performance Monitoring and Reporting for Regulated Rate Providers, Default Supply Providers and Retailers*), with an effective date of January 1, 2019.

Because the approved revisions of Rule 021 and Rule 028 involve system changes, the implementation timing for market participants' system changes was set for June 22, 2019. Although the system implementation for the Rule 021 and Rule 028 was set for June 22, 2019, the AUC would continue to require that the most accurate and up-to-date information be provided, in accordance with Rule 021 and Rule 028 as of January 1, 2019.

On June 11, 2018, Bill 13: *An Act to Secure Alberta's Electricity Future* came into force, which empowered the AUC to apply financial penalties to entities violating an AUC order, rule or decision. The AUC outlined a two-phase process for developing the specified penalties framework contemplated in Bill 13.

In Phase 1, the AUC held stakeholder consultations to review and revise Rule 021 and Rule 028 to implement specified penalties for better customer care and billing rules.

In Phase 2, the AUC consulted with stakeholders to further strengthen the AUC customer care and billing rules by proposing changes to Rule 003. Concurrent with the review of AUC Rule 003, the AUC also introduced and consulted stakeholders on, the new Rule 032. Rule 032 sets out the specific financial penalties for contraventions of the AUC rules listed in the penalty table of the rule.

NATIONAL ENERGY BOARD

Abandonment Hearing Many Islands Pipe Lines (Canada) Limited (NEB Decision MHW-001-2018)

Abandonment - Pipeline - Granted

In this decision, the NEB considered Many Islands Pipe Lines (Canada) Limited ("Many Islands")' application for the abandonment of the Renaissance - North Bronson Pipeline and associated facilities (the "Pipeline").

Pursuant to paragraph 74(1)(d) of the *National Energy Board Act* (the "*NEB Act"*), and with consideration of section 50 of the *National Energy Board Onshore Pipeline Regulations* (the "*OPR*"), the NEB issued Order ZO-M182-005-2018 (the "Order"), granting Many Islands leave to abandon the Pipeline.

Application

Many Islands proposed to abandon the Renaissance – Bronson North Pipeline in place and all associated above ground facilities would be removed. The Pipeline is located primarily in previously disturbed areas within a broader intact forest landscape. Many Islands indicated that abandonment activities would be limited to previously disturbed areas and would be primarily executed within the existing right of way.

Abandonment in Place

Many Islands indicated that it chose to abandon the pipeline in place because pipeline removal would require the use of heavy machinery and increase construction traffic on local roads, which would increase environmental effects and the risk of potential safety issues. The NEB found that Many Islands applied the appropriate rationale for abandoning the pipeline in place.

Indigenous Engagement

The NEB was satisfied with the design and implementation of Many Islands' consultation activities, as well as its commitment to continue consultation activities throughout the lifecycle of the Project.

The Elizabeth Métis Settlement raised concerns regarding the importance of the lands in the vicinity as well as the cumulative effects of development on traditional lands and practices. The Elizabeth Métis Settlement also had specific requests regarding the reclamation, timing of the abandonment work and requested a site visit.

Many Islands contacted the Elizabeth Métis Settlement to discuss their concerns and committed to providing an updated timeline.

Summary

The NEB granted Many Islands leave to abandon the Pipeline.

The NEB determined that carrying out the abandonment project was not likely to cause significant adverse environmental effects. Given the nature and scope of the Project, and the implementation of the NEB's conditions, the NEB was of the view that any residual environmental effects would be of limited geographic extent (limited to the Project site), medium-term (in the order of months or years), reversible and of low magnitude.

Nipigon LNG Corporation Application in respect of TransCanada PipeLines Limited and the TransCanada Mainline Pipeline System (NEB Letter Decision, OF-Tolls-Group1-T211-2018-01 01)

Liquefied Natural Gas - Directions to Provide Facilities and Service

In this decision, the NEB considered Nipigon LNG Corporation ("Nipigon")'s application for orders pursuant to sections 12, 13, 59, and 71 of the *National Energy Board Act* ("*NEB Act*") directing TransCanada PipeLines Limited ("TransCanada") to provide facilities, and service under just and reasonable terms, to connect and transport gas from the TransCanada Mainline pipeline system (the "TransCanada Mainline") to Nipigon's planned liquefied natural gas ("LNG") project (the "Application").

The NEB denied the Application.

The Application

Nipigon requested the following relief:

(a) an Order, pursuant to subsection 71(3) of the *NEB Act,* directing TransCanada to provide adequate and suitable facilities for the interconnection of the Nipigon LNG

Project (the "Project") with the TransCanada Mainline by June 30, 2020. The interconnection would be at a point on the Northern Ontario Line (the "NOL") segment of the TransCanada Mainline west/upstream of TransCanada's Nipigon Compressor Station in the unorganized Township of Ledger (the "Ledger Interconnection");

(b) an Order pursuant to subsections 71(2) and (3) of the *NEB Act*, directing TransCanada to establish a new delivery point at or near the Ledger Interconnection by June 30, 2020;

(c) an Order, pursuant to subsection 71(2) of the *NEB Act*, directing TransCanada to transport and deliver, on a firm basis, up to 7,200 GJ/day of natural gas to Nipigon, commencing June 30, 2020, or so soon thereafter as is reasonably practical in the circumstances (the "Ledger Delivery"); and

(d) an Order, pursuant to section 59, section 71 and Part IV of the *NEB Act*, prescribing just and reasonable terms for the Ledger Delivery, including:

(i) service pursuant to terms consistent with TransCanada's standard renewable firm service agreement for an initial period of 10 years; and

(ii) just and reasonable tolls calculated in a manner determined by the NEB.

According to the Application, despite the proposed Project not being located in a Local Distribution Company ("LDC") franchise area, TransCanada would not proceed with the Ledger Interconnection without written confirmation from the LDCs – Union Gas Limited ("Union") and Enbridge Gas Distribution Inc. ("EGDI") – that Ledger "[was] not a current or potential franchise area". According to the Application, TransCanada said that this requirement stemmed from the Mainline Settlement Agreement between TransCanada, Union, EGDI, and Énergir, L.P. (the "Settlement"). The Settlement contained a no-bypass provision whereby TransCanada would not construct facilities to directly serve LDC customers within the LDCs' franchise areas. According to Nipigon, TransCanada also noted it would not proceed with pre-work for the Ledger Interconnection until Nipigon obtained all provincial approvals.

<u>NEB Findings</u>

The *NEB Act* gives the NEB discretion to:

(a) order a company operating a gas pipeline to provide gas transportation service (section 71(2)(a)); and/or

(b) require a company operating a gas pipeline to provide facilities required for gas transportation service, gas storage, or the junction of the gas pipeline with other transmission facilities (subsection 71(3)).

The NEB denied the Application finding that there was no need to issue the orders and that the public interest would not be served by issuing the orders.

The NEB found that several issues raised in the Application were since dealt with in subsequent filings from TransCanada and the LDCs. Given the confirmation from Union and EGDI that the Project was not within either of their existing franchise areas, TransCanada said that it "could provide the requested service without bypassing Union or EGDI for the sole purpose of serving a customer base of these LDCs". TransCanada also said that it would proceed with the interconnection of the Project through its normal course of business, via the execution of a backstopping agreement with Nipigon, the addition of a new distributor delivery area within Ledger, and application for regulatory approvals. In the NEB's view, this was the most appropriate way to advance the Project.

The NEB found that the reasons provided by Nipigon to grant the orders were not compelling, based on the following:

(a) It would be unfair to TransCanada, its shippers and potential shippers to grant the requested Orders for Nipigon to satisfy financing conditions – the details of which Nipigon did not provide.

(b) Nipigon did not provide any compelling evidence in terms of why its unique financing circumstances warranted the relief requested.

(c) Requiring TransCanada to build interconnection facilities without a financial backstop in place would place an undue burden on the company, and place risk on the Mainline and its shippers.

Summary

The NEB denied granting the Orders requested by Nipigon.

The NEB expected that TransCanada would uphold its commitment to advance discussions with Nipigon as it would normally do with any other party seeking service requiring additional facilities on the Mainline in accordance with its tariff.

Westcoast Energy Inc. Application for the Spruce Ridge Program (NEB Hearing Order GH-001-2018)

Westcoast System Extension - Tolling Methodology

In this decision, the NEB considered Westcoast Energy Inc., carrying on business as Spectra Energy Transmission ("Westcoast")'s application pursuant to section 58 of the *National Energy Board Act* ("*NEB Act*") and section 43 of the *National Energy Board Onshore Pipeline Regulations* ("*OPR*") for authorization to construct and operate the Spruce Ridge Program (the "Project"). The NEB found that it was in the public interest to approve Westcoast's application to construct and operate the Project.

The Project

The Project included two natural gas pipeline loops (Chetwynd Loop and Aitken Creek Loop, approximately 25 kilometres ("km") and 13 km, respectively, in length and the associated facilities which included the addition of two new compressor units at two existing compressor stations ("CS2" and "CS N5"), and minor modifications at two compressor stations ("CS N5" and "CS 16").

The proposed Project would allow Westcoast to provide incremental firm transportation service from receipt points along the Fort Nelson Mainline, Aitken Creek Pipeline, and Fort St. John Mainline. Westcoast received requests for additional Zone 3 firm transportation service to accommodate increasing levels of production from the Montney Formation in northeast British Columbia.

Consultation and Land Matters

The NEB was satisfied that Westcoast proposed suitable mitigation to address the Project's potential land-related effects during the design, construction, and operation of the Project. The NEB found the route, as proposed, was acceptable.

The NEB acknowledged Westcoast's efforts to minimize both the potential area of environmental disturbance of the Project, as well as avoidance of existing municipal development, by proposing a right-of-way that bypassed the District of Chetwynd, and otherwise was largely contiguous with existing linear disturbances.

The NEB found that the requested right-of-way and temporary work space land requirements were necessary to allow for the safe and efficient construction and operation of the Project. The NEB found that Westcoast's anticipated requirements for permanent and temporary land rights were acceptable.

The NEB noted that for the portion of the Project of Mr. Lasser's lands, there was still an opportunity to confirm methods and timing of construction. Therefore, the NEB imposed Condition 12 (Landowner-specific Consultation Update) to ensuring that Westcoast continued to consult with Mr. Lasser, as well as allowing for the participation of Mr. Lasser in planning Project construction activities on his lands.

Matters of Concern to Indigenous People

The NEB found that there was adequate consultation and accommodation for the purpose of the NEB's decision on the Project. The NEB also found that any potential Project impacts on the rights and interests of affected Indigenous peoples were not likely to be significant and can be effectively addressed.

With respect to consultation, the NEB found that:

(a) potentially affected Indigenous peoples were appropriately identified, given the information available at the time, and provided information about the Project; and

(b) Westcoast would continue to consult with Indigenous peoples, including all Indigenous Intervenors, to learn more about their interests and concerns, and address issues they may raise throughout the lifecycle of the Project.

The NEB remained concerned about the cumulative effects of projects, including this Project, on the current use of lands and resources for traditional purposes by Indigenous peoples. However, the NEB found that the cumulative effects of the Project on traditional land and resource use in the Project area would be effectively mitigated by the proposed conditions and commitments.

Engineering Matters

The NEB found that the general design of the Project facilities was appropriate for the intended use and that the facilities will be constructed in accordance with accepted standards for design, construction, and operation. The NEB reminded Westcoast to apply for leave to open pursuant to section 47 of the *NEB Act*, prior to the facilities being placed in operation.

Environment Matters

Environmental and Socio-Economic Assessment

The NEB's Filing Manual guides proponents on what should be included in the Environmental and Socio-Economic Assessment ("ESA"). The Filing Manual notes that an applicant is not expected to provide extensive descriptions of features of the environment that would not be impacted by the Project and that the goal is to: provide information with sufficient detail to identify Project-environment interactions; determine the significance of Project effects; and formulate appropriate mitigation measures and monitoring Programs. In some cases, the effects of a project on certain environmental elements can be predicted and appropriate mitigation proposed regardless of the level and detail of baseline information provided.

The NEB found that Westcoast's ESA methodology was acceptable, based on the following:

(a) Westcoast included sufficient baseline information that was supported by a description of the methodology used and the rationale for that methodology; and

(b) Westcoast's ESA properly analyzed and characterized the level of significance of the potential adverse environmental effects of the Project as required by the Filing Manual.

Environmental Impacts

The NEB found that:

(a) the mitigation to be implemented by Westcoast would minimize the environmental effects of the Project;

(b) Westcoast made reasonable efforts to obtain the latest critical habitat mapping from Environment and Climate Change Canada to plan its Project; and

(c) the Project was not likely to result in any additional adverse impacts to caribou within the Graham and Pine River Local Population Unit.

The NEB noted that Westcoast would conduct post-construction monitoring and that a Post-Construction Monitoring Program ("PCMP") was a key tool towards ensuring that potential adverse effects will be effectively mitigated and where issues are identified, adaptive management will be implemented to address them. To be satisfied that post-construction monitoring was thorough and effective and that reports would be developed and filed, the NEB imposed Condition 20 (Post-Construction Environmental Monitoring Reports which set out requirements for Westcoast's post construction monitoring. The NEB included, as part of Condition 20, a requirement that Westcoast develop a Wetland Functions Monitoring Program.

The NEB imposed Condition 17 requiring offsets and a Caribou Habitat Offset Measures Plan ("OMP"). The OMP must include a final confirmation of the footprint and if combined with another ongoing Westcoast offset program, a demonstration of how the measures are included and how they will be effective.

Economic Feasibility

The NEB found that Westcoast demonstrated a need for the Project and the applied for facilities were likely to be used at a reasonable level over their economic life.

The NEB found that the natural gas resources in the Montney Formation represented adequate supply to support the Project.

Tolling Methodology

Westcoast requested an order from the NEB pursuant to Part IV of the *NEB Act*, affirming that the cost of the Project would be included in the T-North (Zone 3) cost of service and tolled on a rolled-in basis.

The NEB found Westcoast's proposed tolling methodology, using rolled-in cost of service, was appropriate for this Project and would result in just and reasonable tolls. The rolled-in tolling methodology was consistent with Westcoast's existing practice for system expansions. Therefore, the NEB found that the tolling methodology reasonably satisfied section 62 of the *NEB Act*, which requires that the same tolls should apply to all shippers using the same transportation services over the same facilities.

In assessing a proposed tolling methodology, the NEB must be satisfied that a proposed tolling methodology would not result in any unjust discrimination in tolls, service or facilities. The NEB also considered whether the resulting tolls would be just and reasonable, and whether, under substantially similar circumstances and conditions concerning all traffic of the same description carried over the same route, the tolls would be charged equally to all persons at the same rate.

Westcoast's Zone 3 cost of service was allocated on the basis of contract demand volumes only, this method of tolling is referred to as postage stamp tolls. Westcoast explained that there are two postage stamp tolls in Zone 3:

(a) the short haul toll for deliveries to distribution utilities connected to Zone 3 that serve northern communities and for gas movements of 75 km or less other than to the Alliance or NGTL systems; and

(b) the long-haul toll for all other gas movements in Zone 3.

Summary

The NEB found that it was in the public interest to approve Westcoast's application to construct and operate the Project.

The NEB granted an order pursuant to section 58 of the *NEB Act* exempting*:*

(a) the applied for facilities from the application of paragraphs 30(1)(a) and (b) and section 31 of the *NEB Act*; and

(b) the pipeline tie-ins from the application of section 47 of the *NEB Act*.

The NEB also granted an order pursuant to subsection 48(2.1) of the *NEB Act* exempting certain welds for the auxiliary and utility piping systems from the 100 percent non-destructive examination requirement in section 17 of the OPR for the auxiliary and utility systems.

Further, the NEB granted Westcoast an order pursuant to Part IV of the *NEB Act* affirming that the cost of the Spruce Ridge Program will be included in the Transmission North (Zone 3) cost of service and tolled on a rolled-in basis.

TransCanada PipeLines Limited Application for Approval of 2018 to 2020 Mainline Tolls (NEB Decision RH-001-2018)

Canada Mainline - Tolls - Long-term Adjustment Account (LTAA) - Pricing Discretion

In this decision, the NEB considered TransCanada PipeLines Limited ("TransCanada")'s application for approval of tolls for January 1, 2018 to December 31, 2020 and associated approvals (the "Application"). The Application was made pursuant to Parts I and IV of *the National Energy Board Act* ("*NEB Act*") and certain directives in the NEB Decision RH-001-2014 and Order TG-010-2014. The NEB approved the Application as applied for, with the exception of directing TransCanada to return 100 percent of the Long-Term Adjustment Account ("LTAA") balance to shippers in the 2018-2020 period using the over-collection method.

Background

In Decision RH-001-2014, the NEB approved the components of the Mainline 2013-2030 Settlement Agreement (the "Settlement") reached between TransCanada and its three largest customers, Enbridge Gas Distribution Inc. ("EDGI"), Union Gas Limited ("Union), and Énergir, L.P. ("Énergir"), formerly known as Gaz Métro Limited Partnership. In that decision, the NEB approved the toll design for the TransCanada Mainline System ("Mainline") for the 2015 to 2020 period but directed TransCanada to file an application for approval of the 2018 to 2020 Mainline tolls by December 31, 2017.

Prior to making the Application, TransCanada reached an agreement with the three parties to the Settlement regarding tolling matters for the 2018 to 2020 period.

Issues

TransCanada filed the proposed revenue requirements, rate bases and supporting schedules for 2018 to 2020 tolls. TransCanada explained that the revenue requirements and rate bases were updated using a consistent approach with that used in the RH-001-2014 Compliance Filing for 2015 to 2017 tolls (the "Compliance Filing") and that the 2018 revenue requirement was based on TransCanada's 2018 budget.

Intervenors challenged the following issues:

(a) the disposition and allocation of the LTAA in the 2018 to 2020 period;

(b) the appropriateness of continued pricing discretion for Interruptible Transportation ("IT") service and Short-Term Firm Transportation ("STFT") service; and

(c) the appropriateness of TransCanada's proposed allocation of costs and revenues related to Dawn Long-Term Fixed Price ("Dawn LTFP") service.

Long-Term Adjustment Account

The NEB denied TransCanada's proposed LTAA treatment for the 2018 to 2020 period. The NEB found that the Application's approach to return - approximately 3.9 percent of the $1.1 billion LTAA balance each year to shippers in the 2018 to 2020 period - represented an unreasonably large intergenerational cross-subsidy. The NEB found that TransCanada's proposed treatment of the LTAA would not adhere to the cost-based/user-pay tolling principle and would cause unreasonable intergenerational inequity. Therefore TransCanada's proposed treatment of the LTAA did not produce just and reasonable tolls. The NEB found that an alternative allocation method was required.

Section 62 of the *NEB Act* requires that all tolls must be just and reasonable. In determining whether tolls are just and reasonable, the NEB has historically relied on fundamental tolling principles, including the principle of cost-based/user-pay tolls. The NEB stated that tolls should be, to the greatest extent possible, cost-based and that users of a pipeline system should bear the financial responsibility for the costs caused by the transportation of their product through the pipeline. Similarly, the NEB indicated that all reasonable efforts should be made to minimize cross-subsidization.

The cost-based/user-pay principle can be applied in consideration of costs over time, which can be referred to as intergenerational equity. In other words, one generation of shippers subsidizing the costs of another generation of shippers should be avoided.

The NEB decided, to better align with established tolling principles, that 100 percent of the LTAA be returned to shippers in the 2018-2020 period using the over-collection method. The NEB found that returning the entire LTAA balance to shippers in the 2018 to 2020 period will help the overall competitiveness of the Mainline's services and promote increased utilization to the benefit of the Mainline and its shippers.

Pricing Discretion

The NEB approved the continuation of the existing pricing discretion for IT and STFT services for the 2018 to 2020 period.

For the 2018-2020 period, the NEB found that pricing discretion continued to provide an incentive to shippers to contract for firm transportation service to meet firm requirements. Pricing discretion also contributed to the Mainline by achieving positive net revenues. The use of pricing discretion to maximize overall Mainline revenue was an exercise of balance between providing an incentive for shippers, who have firm requirements to contract for the firm service they required, and responding to market opportunities if and when they arise.

The NEB found that the necessity of unlimited pricing discretion for IT and STFT services in a scenario of a segmented Mainline, higher contracting, and lower uncontracted pipeline capacity would require a re-evaluation. For the post-2020 toll application, the NEB directed TransCanada to justify the continuation of unlimited pricing discretion for IT and STFT services, as well as information on contracts, forecast flows, and available capacity by segment.

Transportation by Others Arrangements

The NEB found that the proposed Transportation by Others ("TBO") arrangements applied for by TransCanada provided economic and timing benefitstomeet TransCanada's aggregate requirements and were reasonable. These TBO arrangements included the following features:

(a) TBO costs for 2018 were based on the contract and rate assumptions included in its 2018 budget, and this cost is held constant for 2019 and 2020 at $305.3 million;

(b) TBO costs increased due to new contracts associated with the Dawn LTFP service that commenced in November 2017;

(c) foreign exchange rate changes resulted in an increase of $5 million per year from the amount in the Compliance Filing; and

(d) a reduction in the negotiated Great Lakes Gas Transmission St. Clair to Emerson rate contributed to a reduction of TBO costs of $19 million.

The NEB accepted TransCanada's justification that it entered into TBO arrangements as an alternative to the construction of incremental facilities, or where the economics of operating existing facilities and the service provided by a third-party pipeline offered a better means of meeting TransCanada's aggregate requirements.

Other Revenue Requirement Items and Rate Base

The NEB accepted the proposed components of the 2018-2020 revenue requirement and rate base as applied for by TransCanada as reasonable.

TransCanada updated components of the 2018 to 2020 revenue requirement and rate base using a consistent approach to that used in the Compliance Filing and was based on its 2018 budget. Certain costs were increased by an annual inflation factor of two percent, municipal taxes were increased by three percent, and TBO and Pipeline Integrity and Insurance Deductibles were held constant at the 2018 level.

Discretionary Miscellaneous Revenue

The NEB found the discretionary miscellaneous revenue ("DMR") forecast applied for by TransCanada to be reasonable. This DMR forecast was based on the following:

(a) DMR forecast for 2018 to 2020 was lower compared to the Compliance Filing forecast of DMR, in which the DMR level was forecast to be $60 million for each year from 2018 to 2020; and

(b) in the Application, the DMR forecast was updated to $32 million for 2018 and $25 million for both 2019 and 2020, which reflected a continued trend towards more firm contracting on the Mainline that was occurring since the RH-003-2011 Decision.

TransCanada further explained that, as Mainline shippers increasingly rely on firm contracts to meet their market requirements, the use and resulting revenues from discretionary services was expected to be reduced. Depreciation

The NEB approved the proposed depreciation rates applied for by TransCanada.

TransCanada stated that its proposed changes to depreciation rates increase the depreciation rate expenses of $110.4 million, $105.7 million and $113.3 million for 2018, 2019 and 2020, respectively. TransCanada submitted that the depreciation expenses were higher than in the Compliance Filing primarily due to an increase in the depreciation rates and higher capital additions.

Allocation of Dawn LTFP Net Revenues

The NEB found the proposed allocation of the Dawn LTFP Net Revenue to the segments based on the path weighted distance in each segment, as applied for by TransCanada, to be reasonable.

TransCanada submitted that the Dawn LTFP Net Revenue would be allocated to the segments based on the path weighted distance in each segment. With 1,500 TJ/d of Dawn LTFP service being provided using 50 percent through the northern route and 50 percent through the southern route, the Dawn LTFP Net Revenue would be allocated 9.64 percent to the Eastern Triangle segment, 53.72 percent to the Northern Ontario Line segment and 36.64 percent to the Prairies segment.

Dawn LTFP net revenues (revenue less abandonment surcharges and certain costs) totalled $240 million, $246 million, and $249 million for each of 2018, 2019 and 2020, respectively. TransCanada submitted that, absent the net revenues associated with Dawn LTFP, the revenue requirement used to derive 2018 to 2020 Mainline tolls would be approximately 16 percent higher.

Summary

The NEB approved the Application as applied, with the exception of directing TransCanada to return 100 percent of the LTAA balance to shippers in the 2018-2020 period using the over-collection method.