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.

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SUPREME COURT OF CANADA

Mikisew Cree First Nation v. Canada (Governor General in Council), 2018 SCC 40

Constitutional Law — Aboriginal Treaty Rights - Crown Duty to Consult

In this decision, the Supreme Court of Canada ("SCC") considered an appeal by the Mikisew Cree First Nation from the judgment of the Federal Court of Appeal ("FCA") in *Canada (Governor General in Council) v. Mikisew Cree First Nation*, 2016 FCA 311 (the "FCA Decision").

The SCC dismissed the appeal (upholding the FCA Decision) on the grounds that judicial review to the Federal Court under the *Federal Courts Act* was not available for the actions of federal ministers in the parliamentary process.

The nine members of the SCC panel were unanimous in the result that the appeal should be dismissed on the grounds that judicial review under the *Federal Courts Act* was not available. However, the Court was divided with respect to the issues regarding the Crown's duty to consult as part of the law-making process.

<u>Background</u>

The Mikisew is a band within the meaning of the *Indian Act*, whose traditional territory is situated primarily in northeastern Alberta.

The Mikisew are descendants of First Nations that signed Treaty No. 8 ("Treaty 8") with the Crown. Under Treaty 8, the Aboriginal signatories ceded large amounts of land-across northern Alberta, British Columbia, Saskatchewan, and the southern portion of the Northwest Territories. The lands were ceded to the Crown in exchange for certain guarantees including protecting the right of the signatories to hunt, trap, and fish.

In April 2012, two pieces of omnibus legislation with significant effects on Canada's environmental protection regime were introduced into Parliament. The Mikisew were not consulted on either of these omnibus bills at any stage in their development or prior to the granting of royal assent.

Federal Court Decision

The Mikisew brought an application for judicial review in the Federal Court under ss. 18 and 18.1 of the *Federal Courts Act*, seeking various declarations and orders concerning the Minister's duty to consult them with respect to the introduction and development of the omnibus bills. The Mikisew argued that the Crown had a duty to consult them on the development of the legislation since it had the potential to adversely affect their treaty rights to hunt, trap, and fish under Treaty No. 8. For the reasons set out in *Mikisew Cree First Nation v. Canada (Minister of Aboriginal Affairs and Northern Development)*, 2014 FC 1244, the reviewing judge granted a declaration to the effect that the duty to consult was triggered and that the Mikisew were entitled to notice of the relevant provisions of the bills, as well as an opportunity to make submissions.

Federal Court of Appeal Decision

On appeal, a majority of the FCA concluded that the reviewing judge erred by conducting a judicial review of legislative action contrary to the *Federal Courts Act*. The majority held that when ministers develop policy, they act in a legislative capacity and their actions are immune from judicial review. The FCA found the reviewing judge's decision to be inconsistent with the principles of parliamentary sovereignty, the separation of powers, and parliamentary privilege. Further, imposing a duty to consult in the legislative process would be impractical and would fetter Parliament's law-making capacity.

The Mikisew appealed the FCA Decision to the SCC.

<u>The SCC Decision</u>

The SCC was unanimous in its agreement with the FCA's conclusion that the Federal Court lacked the jurisdiction to consider the Mikisew's judicial review application, based on the following:

(a) For the Federal Court to have jurisdiction over a claim, it must have a statutory grant of jurisdiction (citing *Windsor (City) v. Canadian Transit Co.*, 2016 SCC 54), at para 34).

(b) Two potential statutory grants of jurisdiction were at issue in this appeal, namely sections 17 and 18 of the *Federal Courts Act*.

<u>Section 17 of the *Federal Courts Act*</u>:

(a) Section 17(1) provides that the "Federal Court has concurrent original jurisdiction in all cases in which relief is claimed against the Crown." Further, s. 2(1) of the Act defines the Crown as "Her Majesty in right of Canada."

(b) Her Majesty in right of Canada does not extend to executive actors when they are exercising "legislative power" (citing *Fédération Franco-Ténoise v R*, 2001 FCA 220 at para 58).

(c) Here, the Mikisew challenged actions that were legislative in character.

(d) It followed that the Mikisew's judicial review application was not against "the Crown" in its executive capacity and, therefore, the Federal Court lacked jurisdiction under section 17 of the *Federal Courts Act* to consider the Mikisew's claim.

<u>Section 18 of the *Federal Courts Act*</u>:

(a) Sections 18 and 18.1 only grant the Federal Court jurisdiction to judicially review action taken by "any federal board, commission or other tribunal."

(b) A "federal board, commission or other tribunal" is defined in section 2, subject to certain exceptions, as a body exercising statutory powers or powers under an order made pursuant to a prerogative of the Crown.

(c) Section 2(2) specifically excludes the "Senate, the House of Commons, any committee or member of either House." - and is designed "to preclude judicial review of the legislative process at large."

(d) As such, when developing legislation, ministers do not act as a "federal board, commission or other tribunal" within the meaning of section 2.

Justice Karakatsanis held that the *Federal Courts Act* does not allow for judicial review of parliamentary activities. Cabinet and ministers do not act pursuant to statutory powers when developing legislation; but rather, pursuant to their legislative powers under Part IV of the *Constitution Act, 1867*.

<u>Duty to Consult:</u>

As noted, the Court was divided with respect to the issue of whether the duty to consult applies to the law-making process.

While the panel members all considered it important to consider this issue in the circumstances, the Court was split in its reasons and result. A majority of the Court determined, in three separate sets of reasons, that forming and passing legislation does not trigger the duty to consult. Where the majority disagreed was the extent to which the courts can limit or restrict Parliament's power to pass legislation. A minority of the Court found that enacting legislation with the potential to adversely affect Aboriginal rights did give rise to a duty to consult, and legislation enacted in breach of that duty could be challenged directly for relief.

Reasons of Karakatsanis J. (Wagner C.J. And Gascon J. Concurring)

Justice Karakatsanis held that the honour of the Crown did not give rise to a justiciable duty to consult when ministers develop legislation that could adversely affect the Mikisew's treaty rights. The law-making process — the development, passage, and enactment of legislation — does not trigger the duty to consult. In her view, the separation of powers and parliamentary sovereignty dictate that courts should forebear from intervening in the law-making process, such as was the case here. Justice Karakatsanis described the duty to consult doctrine as being "ill-suited for legislative action."

Parliamentary sovereignty mandates that the legislature can make or unmake any law it wishes, within the confines of its constitutional authority.

Justice Karakatsanis found that:

(a) recognizing that a duty to consult applied during the law-making process might require courts to improperly trespass onto the legislature's domain; and

(b) recognizing that the elected legislature had specific consultation obligations might constrain it in pursuing its mandate and therefore undermine its ability to act as the voice of the electorate.

Justice Karakatsanis found that the related doctrine of parliamentary privilege excluded the law-making process from the reach of judicial interference. Parliamentary privilege protects control over "debates or proceedings in Parliament." The existence of this privilege generally prevents courts from enforcing procedural constraints on the parliamentary process.

Justice Karakatsanis also addressed the practical concerns that applying a duty to consult to the development of legislation by ministers would raise:

(a) If changes were made to a proposed bill to address concerns raised during consultation, these changes could later be undone by Parliament, as it is free to amend the proposed law. This might limit the possibility of meaningful accommodation.

(b) Private member bills would not trigger the duty, rendering the approach incongruous.

(c) In the long chain of events contributing to the development of legislation, disentangling what steps the duty to consult applied to (because they are executive) and what actions were immune (because they were parliamentary) would be an enormously difficult task.

Justice Karakatsanis concluded that no aspect of the law-making process, from the development of legislation to its enactment, triggers a duty to consult.

She clarified that this conclusion was not to suggest that Aboriginal groups would be left without a remedy if the enactment of legislation undermined section 35 rights. Justice Karakatsanis affirmed that if legislation infringes section 35, it may be declared by the courts to be invalid pursuant to section 52(1) of the *Constitution Act, 1982*.

Reasons of Abella J. (Martin J. Concurring)

In Justice Abella’s view, the enactment of legislation with the potential to adversely affect rights protected by section 35 of the *Constitution Act, 1982* does give rise to a duty to consult, and legislation enacted in breach of that duty may be challenged directly for relief.

Reasons of Brown J.

Brown J considered that the reasons of Justice Karakatsanis were “less than categorical” in accepting that parliamentary privilege and the separation of powers preclude judicial imposition of the duty to consult.

Justice Brown held that:

(a) Categorically, the development, introduction, consideration and enactment of bills is the exercise of legislative authority, and is not Crown conduct - i.e., executive conduct - which triggers the duty to consult. The Crown does not enact legislation, Parliament does.

(b) The absence or inadequacy of consultation may be considered only once the legislation at issue has been enacted, and then, only in respect of a challenge under s. 35 to the substance or the effects of such enacted legislation, as opposed to a challenge to the legislative process.

Justice Brown found that the reasons of Justice Karakatsanis unnecessarily left open the possibility that legislation which does not infringe s. 35 rights but may "adversely affect" them, might be found to be inconsistent with the honour of the Crown. Brown J. considered it inappropriate to raise the possibility that legislation which adversely affected section 35 rights might be declared inconsistent with the honour of the Crown and that it would undercut the principles of separation of powers and parliamentary privilege. Further, Brown J. considered that this would cast the law into considerable uncertainty, with deleterious effects on Indigenous peoples, and on all who rely upon the efficacy of validly enacted and constitutionally compliant laws.

Reasons of Moldaver J (Côté and Rowe JJ Concurring)

Writing for himself, Côté, and Rowe JJ, Justice Moldaver affirmed the reasons of Brown J. In addition, he addressed three further points:

(a) The fact that the duty to consult had not been recognized as a procedural requirement in the legislative process would not leave Aboriginal claimants without effective remedies once legislation is enacted (citing *R v Sparrow;* [1990] SCR 1075, *Haida Nation*).

(b) Recognizing a constitutionally mandated duty to consult during the process of preparing legislation would be highly disruptive to the carrying out of that work and could effectively grind the day-to-day internal operation of government to a halt.

(c) Recognizing a duty to consult during the law-making process would result in courts routinely being asked to interfere in the exercise of legislative discretion regarding whether and at what stage such consultation takes place, which would offend the principle separation of powers.

ALBERTA ENERGY REGULATOR

Request for Regulatory Appeal by R.A. Brown of Licence Issued to Whitecap Resources Inc.

Eligible Person - Potential Impacts

In this decision, the AER considered R.A. Brown's ("Mr. Brown") request for regulatory appeal of the AER's decision to issue Whitecap Resources Inc. ("Whitecap") Well Licence No. 04891138 (the "Decision").

The AER found that Mr. Brown was not an eligible person and dismissed his request for regulatory appeal of the Decision.

Eligibility to Apply for Regulatory Appeal

Section 38 of the *Responsible Energy Development Act* ("*REDA*") governs requests for regulatory appeal and provides that an eligible person may request a regulatory appeal. Section 36(b)(ii) of *REDA* defines an "eligible person" as a person who is directly and adversely affected by a decision made under an energy resource enactment.

The AER found that Mr. Brown was not an eligible person under *REDA* on the basis that he was not directly and adversely affected by the Decision.

Concerns Raised

Mr. Brown raised concerns of potential impacts to his lands due to well location, flaring, noise, and traffic.

The AER found that Mr. Brown was not directly and adversely affected by the Decision, based on Whitecap's compliance with regulatory requirements, including:

(a) with respect to the well locations, that Whitecap would comply with the requirements for setbacks and notification set out in *Directive 056: Energy Development Applications and Schedules*;

(b) with respect to the flaring concerns, that Whitecap would comply with *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*, while no flaring was expected during normal drilling, and upon completion of the well, flaring would only be required at intermittent stages; and

(c) regarding noise concerns, that Whitecap would comply with the applicable permissible sound level and requirements in *Directive 038: Noise Control*.

Summary

The AER found that Mr. Brown was not directly and adversely affected by the Decision and, as a result, that Mr. Brown was not an eligible person. The AER, therefore, dismissed Mr. Brown's request for regulatory appeal.

AER Bulletin 2018-27: New Edition of Directive 054: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

Directive 054 - In Situ

In this bulletin, the AER announced the release of a new edition of *Directive 054: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes*. The AER indicated that two changes were made:

1. Operators are no longer required to give annual in-person performance presentations for all *in situ* commercial and experimental schemes.
2. However, digital versions of the presentations must be submitted annually, and the AER may still require an operator to attend and present its annual performance presentation.

AER Bulletin 2018-28: New Edition of Directive 056: Energy Development Applications and Schedules and New Manual

Directive 056 - Energy Development

In this bulletin, the AER announced the release of a new edition of *Directive 056: Energy Development Applications and Schedules* and a new manual, *Manual 012: Energy Development Applications; Procedures and Schedules*.

There were no substantive technical requirement changes, but the Directive was restructured.

Technical Requirements

Technical requirements state how energy development must occur and what information must be submitted to the AER. Previous editions of

Directive 056 spread participant involvement and audit requirements throughout multiple sections. These requirements were consolidated in their respective sections and were otherwise left unchanged.

Procedural Instructions

Procedural instructions lay out the specifics of how information is to be formatted and submitted. These instructions change more frequently as information systems evolve. The procedural instructions were removed from the Directive itself and are now available in the new Manual 012, along with applicable schedules and how-to sections. This includes procedural instructions that were previously embedded in technical requirements. Procedural instructions related to pipelines were updated because such information is now submitted through OneStop. No other procedural instructions were changed.

AER Bulletin 2018-29: New Edition of Directive 020: Well Abandonment

Directive 020 - Well Abandonment

In this bulletin, the AER announced the release of the new edition of *Directive 020: Well Abandonment*.

The new edition gives licensees more options when determining the depth at which to set isolation devices when abandoning lower-risk injection or disposal wells and producing wells with an H_2S concentration of less than 15 percent. Licensees may either set the plug within 15 metres above the perforations, single-zone open-hole interval, and liner top or choose a depth that meets the following criteria:

- the depth is within the same formation as the completed interval or within the next formation, provided there are no other effective porous zones located between the bridge plug setting depth and completed interval;
- the cement top behind the casing extends above the top of the formation in which the isolation device will be set; and
- the depth is below the base of groundwater protection.

No other requirements were changed.

AER Bulletin 2018-30: New Edition of Directive 013: Suspension Requirements for Wells

Directive 013 - Optional Annual Inspections

In this bulletin, the AER announced the release of a new edition of *Directive 013: Suspension Requirements for Wells*. The Directive was updated to give licensees that have an AER-approved closure plan the option of performing annual inspections of low-risk wells that have been inactive for ten or more years instead of conducting downhole suspension and performing periodic pressure testing.

No other requirements were changed.

ALBERTA UTILITIES COMMISSION

Rebasing for the 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities Second Compliance Proceeding (Decision 23355-D02-2018)

Rebasing Applications - Distribution Utilities

In this decision, the AUC considered the second compliance filing for the interim notional 2017 revenue requirement and 2018 base K-bar for the 2018-2022 performance-based regulation ("PBR") plans for the following Alberta electric and gas distribution utilities:

- AltaGas Utilities Inc.,
- ATCO Electric Ltd. (distribution),
- ATCO Gas and Pipelines Ltd. (distribution),
- ENMAX Power Corporation (distribution) ("ENMAX"),
- EPCOR Distribution & Transmission Inc. (distribution) ("EPCOR"), and
- FortisAlberta Inc. ("Fortis")

(collectively, the "Distribution Utilities").

While the AUC accepted the general principles and methodologies utilized by each of the Distribution Utilities for calculating their respective 2018 PBR rates, the AUC did not approve any specific rates in this decision since the directions throughout this and other decisions would result in changes to 2018 rates.

The AUC directed each of the Distribution Utilities to file an update in its 2019 annual PBR rate adjustment filing, providing the 2018 rate schedules and incorporating the directions in this decision. The AUC further directed the Distribution Utilities to update their respective 2019 PBR rates, as required.

<u>Background</u>

The PBR framework provides for annual rates adjustments based on an indexing mechanism that tracks the rate of inflation ("I") less a productivity offset ("X") factor, referred to as the I-X factor.

The I-X factor represents the expected increase in the price of inputs, I, offset by the X factor, which represents the expected efficiency improvements the Distribution Utilities are expected to achieve during the PBR plan period.

The I-X mechanism is intended to sever the link between a utility's costs of service ("COS") and the revenue it receives in rates, for the term of the applicable PBR plan. The objective of PBR is to incent utilities to maximize their returns by improving efficiency, rather than by increasing their COS, as may be the case under traditional COS regulation.

2018-2022 PBR Plans Decision

In Decision 20414-D01-2016 (Errata) the ("2018-2022 PBR Plans Decision"), the AUC set out the parameters of the 2018-2022 PBR plans for the Distribution Utilities.

In the 2018-2022 PBR Plans Decision, the AUC determined that the going-in rates would be based on a notional 2017 revenue requirement developed using actual, pre-2017 costs that the Distribution Utilities incurred during the years of the preceding 2013-2017 PBR plan (2015-2017 for ENMAX), with any necessary adjustments to reflect individual utility anomalies. The AUC also approved the methodology for determining the components of the 2017 notional revenue, including the following:

(a) the operating and maintenance ("O&M") cost component based on the utility's lowest O&M cost year in the preceding PBR term, restated to 2017 dollars using the approved I-X and Q values; and

(b) the capital component of the notional 2017 revenue requirement calculated using the 2016 actual closing rate base and adding the 2017 capital additions, split between capital additions that were covered by the I-X mechanism in 2017 and those that were subject to capital tracker treatment in 2017:

   (i) for capital additions covered by the I-X, the AUC directed parties to use the four-year average of 2013-2016 actual capital additions (2015-2016 additions for ENMAX) restated to

2017 dollars using the approved I-X and Q values; and

(ii) for capital additions subject to capital tracker treatment, the actual approved capital additions were to be used.

Continued from prior generation PBR plans, the AUC designated the forecast percentage change in billing determinants in any given PBR year as "Q."

The AUC explained that multiplying the going-in revenue requirement for similar types of expenditures by the I-X index and adjusting for Q resulted in a proportional allocation of the impact on revenue of any changes in billing determinants. For electric Distribution Utilities under the price cap PBR plan, this percentage change was calculated across all billing determinants, including energy, demand, and the number of customers. For gas Distribution Utilities under the revenue-per-customer cap PBR plan, the percentage change was calculated as a forecast weighted-average change in the number of customers among rate classes.

Significant changes approved in the 2018-2022 PBR Plans Decision from the previous generation of PBR plans included the following:

(a) a requirement that going-in rates be based on actual costs experienced in the previous term and not on forecasted costs for the next term;

(b) a determination that the X Factor (inclusive of a productivity growth and stretch factor) would be equal to 0.3 percent for the next PBR term, a reduction from the previously approved 1.16 percent; and

(c) changes to the capital funding mechanism, whereby most capital additions would be funded through a mechanism tied to the I-X Mechanism (the K-bar parameter) rather than being COS based, as was the case for capital projects eligible for capital tracker treatment under the previous generation of PBR plans.

First Compliance Filing

The AUC subsequently issued Decision 22394-D01-2018 dealing with the first compliance proceeding (the "First Compliance Decision"), pursuant to the AUC's directions in the 2018-2022 PBR Plans Decision.

In the First Compliance Decision, the AUC made directions to the Distribution Utilities requiring modification to various components of the notional 2017 revenue requirement and base K-bar amount. The AUC directed each of the Distribution Utilities to file a second compliance application reflecting the directed modifications.

<u>Summary</u>

In this second compliance filing decision, the AUC found the applied-for notional 2017 revenue requirement and 2018 base K-bar amounts generally to be in alignment with the AUC's directions in the 2018-2022 PBR Plans Decision and the First Compliance Decision.

For the 2018 base K-bar calculations, the AUC approved the Distribution Utilities using the parameters approved in Decision 22570-D01-2018 (the "2018 Generic Cost of Capital Decision"), namely:

(a) return on equity ("ROE") of 8.5 percent; and

(b) a deemed equity ratio of 37 percent for all the Distribution Utilities, other than AltaGas, for which the AUC approved a deemed equity ratio of 39 percent.

<u>2018 I Factor and the Resulting I-X Index for 2018</u>

The AUC approved the 2018 I factor of 0.10 percent and the resulting I-X index value of negative 0.20 percent for 2018.

For 2018, the AUC found that all Distribution Utilities followed the approved methodology and calculated an inflation factor of 0.10 percent for use in their 2018 PBR rate adjustment formulas. Together with the X factor of 0.30 percent approved in the 2018-2022 PBR Plans Decision, this I factor resulted in an I-X index of negative 0.20 percent for 2018.

The AUC found the Distribution Utilities' calculations of the 2018 I factor to be consistent with the methodology confirmed in the 2018-2022 PBR Plans Decision. The AUC also verified that the Distribution Utilities used the correct Statistics Canada data from the prior year's I factor filing as the basis for this year's I factor calculations.

2018 Interim Efficiency Carryover Mechanism Amounts

The AUC previously approved an efficiency carryover mechanism ("ECM") to encourage the Distribution Utilities to continue to make cost-saving investments near the end of the PBR term and discourage gaming regarding the timing of capital projects. Only the Distribution Utilities that were on the 2013-2017 PBR plans included the ECM amounts in their 2018 PBR rates.

The AUC found that in their second compliance applications, the Distribution Utilities calculated their respective 2018 interim ECM dollar amounts in accordance with AUC directions in the amounts shown in the table below:

Table: 2018 Interim ECM Amounts

Distribution Utility	ROE add-on (%)	2018 Interim ECM Amount ($ million)
AltaGas	0.5	0.889
ATCO Gas (North)	0.5	3.395
ATCO Gas (South)	0.5	2.836
ATCO Electric	0.5	6.050
EPCOR	0.5	2.090
Fortis	0.5	5.786

The AUC found that the two non-tax-paying Distribution Utilities, EPCOR and Fortis, calculated their respective 2018 interim ECM amounts in accordance with the AUC's direction.

The AUC was satisfied with how the three tax-paying Distribution Utilities calculated their respective 2018 interim ECM amounts, finding that it was reasonable:

(a) for the tax-paying utilities to gross up the ECM amounts for income tax because they would have to pay tax on any revenue received from the ECM and that the ROE used in the calculation represented an after-tax amount; and

(b) for AltaGas to use weather-adjusted ROE in its ECM calculation, since AltaGas did not have a weather deferral account.

The AUC approved the interim 2018 ECM amounts shown in the table above. These ECM amounts would be finalized following the determination of final notional 2017 mid-year rate base amounts.

Z Factor Materiality Threshold

The Z factor allows for an adjustment to a distribution utility's rates in order to account for a significant financial effect from an exogenous event and for which the distribution utility had no other reasonable opportunity to recover the costs under the PBR formula.

The AUC was satisfied with the Z factor threshold calculations for the Distribution Utilities as set out in the table below.

Utility	Z Factor Threshold
	($ million)
AltaGas	0.52
ATCO Gas (North)	1.98
ATCO Gas (South)	1.66
ATCO Electric	3.53
ENMAX	1.79
EPCOR	1.67
Fortis	4.63

The AUC found that the calculated threshold amounts shown above were consistent with the methodology prescribed by the AUC in the 2018-2022 PBR Plans Decision and, accordingly, approved these Z factor threshold amounts.

2018 Q

The AUC confirmed the use of previously approved forecast (for EPCOR) and approved the forecast (for all other Distribution Utilities) billing determinants for 2018 on which the Q values were calculated. The AUC approved the 2018 Q values for each Distribution Utility as shown in the table below.

Distribution Utility	Q value (%)
AltaGas	2.03
ATCO Electric	2.05
ATCO Gas (North)	1.16
ATCO Gas (South)	1.35
ENMAX	0.54
EPCOR	0.55
Fortis	0.20

Going-In Rates and 2018 PBR Rates

The Distribution Utilities calculated their going-in rates based on the notional 2017 revenue requirement. To arrive at the 2018 PBR rates, the Distribution Utilities escalated the going-in rates by the 2018 I-X index of negative 0.2 percent and applied the 2018 K-bar and Y factors.

The AUC accepted the general principles and methodologies utilized by each of the Distribution Utilities for calculating their respective 2018 PBR rates. However, the AUC did not approve any specific rates in this decision, given the AUC's directions regarding the notional 2017 revenue requirement, 2018 base K-bar and Y factors.

Y Factor

Y factor costs are costs that are flowed through to customers. The AUC found that the applied-for Y factor true-up adjustments were adequately supported and properly calculated. The AUC also found the forecasting methodologies provided in the applications and supporting information provided in information request responses were reasonable and consistent with the methodologies used in previous PBR annual filings.

The AUC directed each of the tax-paying utilities to confirm whether and when it planned to apply for any adjustments associated with the removal of the Y factor for tax timing differences, in accordance with provisions of the 2018 Generic Cost of Capital Decision.

Utilization of Riders

The AUC approved the continuation of the Distribution Utilities' previously approved riders.

The AUC found that these riders were necessary to address flow-through or AUC directed items (i.e., items relating to Y factors) approved for inclusion in the Distribution Utilities' 2018-2022 PBR plans.

Summary

The AUC did not approve any specific rates in this decision since the AUC's directions throughout this and other decisions would result in changes to 2018 rates. However, the AUC accepted the general principles and methodologies utilized by each of the Distribution Utilities for calculating its 2018 PBR rates.

The AUC directed each of the Distribution Utilities to file an update in its 2019 annual PBR rate adjustment filing, providing the 2018 rate schedules and incorporating the directions in this decision. The AUC further directed the Distribution Utilities to update their 2019 PBR rates, as required.

The Office of the Utilities Consumer Advocate - Decision on Preliminary Question - Application for Review of Decision 22357-D01-2018 EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan (Decision 23559-D01-2018)

Review Application - Denied

In this decision, the AUC considered an application by the Office of the Utilities Consumer Advocate ("UCA") requesting a review of Decision 22357-D01-2018 regarding EPCOR Energy Alberta GP Inc.'s ("EPCOR") 2018-2021 Energy Price Setting Plan (the "Original Decision").

The AUC denied the request for review on the basis that the UCA failed to demonstrate that an error of fact, law or jurisdiction was apparent on the face of the Original Decision or otherwise existed on a balance of probabilities.

Background

The Original Decision considered EPCOR's application for approval of its 2018-2021 Energy Price Setting Plan ("EPSP") in Proceeding 22357 (the "Original Proceeding").

In the Original Decision, the AUC hearing panel approved EPCOR's proposed EPSP, which established the pricing of electricity for its regulated rate option ("RRO") customers in the distribution service areas of EPCOR Distribution and Transmission Inc. ("EDTI") and FortisAlberta Inc. ("Fortis"). The EPSP approved by the hearing panel included the following elements:

(a) a descending clock auction format for the procurement of energy;

(b) procurement of approximately 50 percent of the forward market energy products for each month through full-load strips, provided for by a standardized contract for the full-load product through the Natural Gas Exchange;

(c) procurement of the remaining 50 percent by way of fixed block products (either 7X24 flat blocks or 7X16 peak blocks); and

(d) a method for calculating the risk margin, referred to as commodity risk compensation ("CRC"), based on competitive-market-determined prices calculated as the difference between the weighted-average procurement price of the full-load portfolio and the weighted-average procurement price of the fixed block portfolio.

Legislation

RRO providers, including EPCOR, are governed by the *Electric Utilities Act* ("*EUA*") and the *Regulated Rate Option Regulation*. Section 103 of the *EUA* requires the owner of a distribution system to prepare a regulated rate tariff for the purpose of recovering prudent costs of providing electricity services to eligible customers.

Section 5 of the *Regulated Rate Option Regulation* provides for a determination of a risk margin. Risk margin, pursuant to section 1(l), means "the just and reasonable financial compensation that an owner's regulatory authority approves for the owner based on the financial risks (i) that remain with the owner, and (ii) that are associated with the supply of electricity services to regulated rate customers."

Section 6(1) of the *Regulated Rate Option Regulation* sets out the matters to be considered by the AUC when considering approval of a regulated rate tariff:

(a) a regulated rate tariff, including the risk margin described in section 5, must provide the owner with a reasonable opportunity to recover the prudent costs and expenses incurred by the owner [s 6(1)(a)];

(b) a regulated rate tariff must allow for a reasonable return for the obligation on the owner to provide electricity services [s 6(1)(b)(i)];

(c) the risk margin described in section 5 must not be considered as a part of that reasonable return [s 6(1)(b)(i)];

(d) a risk margin must provide the owner with just and reasonable financial compensation for the risks described in section 5 [s 6(1)(c)];

(e) a regulated rate tariff must not impede the development of an efficient electricity market based on fair and open competition in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of any electricity market participant [s 6(1)(d)]; and

(f) the price setting plan must ensure that the procurement risk of acquisition remains with the owner [s 6(1)(f)].

Alleged Grounds for Review

The UCA asserted that the hearing panel committed several errors of law, fact and/or jurisdiction with respect to findings contrary to sections 6(1)(b), 6(1)(d) and 6(1)(f) of the *Regulated Rate Option Regulation*. Specifically, the UCA asserted that the hearing panel made the following errors:

(a) approving a risk margin as part of EPCOR's reasonable return, contrary to section 6(1)(b)(ii) of the *Regulated Rate Option Regulation*;

(b) concluding that EPCOR would remain responsible for the procurement of 100 percent of the energy required to satisfy its obligations as an RRO provider, such that the procurement risk of acquisition remained with EPCOR, contrary to section 6(1)(f) of the *Regulated Rate Option Regulation*; and

(c) failing to consider whether smaller entities may be at a disadvantage in supplying full-load product and whether entities with a physical position have an advantage, contrary to section 6(1)(d) of the *Regulated Rate Option Regulation*.

<u>The AUC Review Process</u>

Pursuant to section 10 of the *Alberta Utilities Commission Act* ("*AUCA*"), the AUC has authority to review its own decisions. AUC Rule 016: *Review of Commission Decisions* ("Rule 016") sets out the process for considering an application for review.

Section 6(3)(a) of Rule 016 provides that the AUC may grant a review where the existence of an error of fact, law or jurisdiction is either apparent on the face of the decision or otherwise exists on a balance of probabilities that could lead the AUC to materially vary or rescind the decision.

The AUC review panel reiterated the following principles from previous review decisions:

- decisions are intended to be final; a review should only be granted in those limited circumstances described in Rule 016;
- the review process is not intended to provide a second opportunity for parties with notice of the application to express concerns about the application that they chose not to raise in the original proceedings; and
- findings of fact and inferences of fact made by the hearing panel are entitled to considerable deference, absent an obvious or palpable error.

<u>Ground 1: The AUC Erred in its Determination of the Risk Margin Contrary to Section 6(1)(b)(ii)</u>

Section 6(1)(b)(i) requires that a regulated rate tariff allow for a reasonable return for the obligation to provide electricity services. Pursuant to section 6(1)(b)(ii), the risk margin must not be considered as part of the reasonable return. This risk and return framework is applied to the services of EPCOR, as an RRO provider.

The review panel found that the hearing panel's assessment of the risk margin under EPCOR's EPSP proposal did not contravene section 6(1)(b)(ii) and was made after weighing the evidence and argument before it. The review panel concluded that there was no reviewable error that was apparent on the face of the record or otherwise existed on a balance of probabilities that could lead the AUC to materially vary or rescind the decision.

<u>Ground 2: The AUC Erred in Concluding that EPCOR's EPSP was Consistent with Section 6(1)(f)</u>

Section 6(1)(f) of the *Regulated Rate Option Regulation* requires that a regulated rate tariff ensures that the procurement risk of acquisition remains with the owner.

With respect to the hearing panel's finding that the EPSP complied with section 6(1)(f) of the *Regulated Rate Option Regulation*, the review panel concluded that the UCA did not show that an error of fact, law or jurisdiction was either apparent on the face of the Original Decision or otherwise existed on a balance of probabilities that could lead the AUC to materially vary or rescind the Original Decision. In coming to this conclusion, the review panel found that:

(a) contrary to the UCA's assertions, the hearing panel's statutory analysis demonstrated the linkages among the statutory provisions and specifically identified who bore the financial risk associated with meeting the monthly load obligations;

(b) based on this analysis, the hearing panel found that the procurement risk of acquisition remained with EPCOR and that the CRC methodology, also known as the risk margin, did not violate section 6(1)(f); and

(c) the UCA failed to establish that the hearing panel's conclusions or statutory analysis in finding that the EPSP was consistent with section 6(1)(f) resulted in an error of fact, law or jurisdiction that was apparent on the face of the decision or on a balance of probabilities.

Accordingly, the UCA's request for review on this ground was denied.

Ground 3: The AUC Erred in Approving the EPSP in Contravention of Section 6(1)(d)

Section 6(1)(d) of the *Regulated Rate Option Regulation* requires that a regulated rate tariff does not impede the development of an efficient market for electricity based on fair and open competition in which neither the market nor the structure of the Alberta electric industry is distorted by unfair advantages of any participant.

With respect to the hearing panel's finding that the EPSP complied with section 6(1)(d) of the *Regulated Rate Option Regulation*, the review panel concluded that the UCA did not show that an error of fact, law or jurisdiction was either apparent on the face of the Original Decision or otherwise existed on a balance of probabilities that could lead the AUC to materially vary or rescind the Original Decision. In coming to this conclusion, the review panel found that:

(a) upon weighing the evidence, the hearing panel found that a number of physical and financial suppliers may participate in the auction;

(b) the hearing panel determined that the plan was structured, with a full-load strip product, with the goal to ensure that prices were set in the competitive market;

(c) in coming to its findings, the hearing panel weighed the evidence of all the parties in relation to the potential acquisition process; and

(d) the UCA failed to establish that the hearing panel's findings resulted in an error of fact, law or jurisdiction that was apparent on the face of the decision or on a balance of probabilities.

Accordingly, the UCA's request for review on this ground was denied.

Decision

The AUC denied the review application based on its determination that the UCA failed to demonstrate that an error of fact, law or jurisdiction was apparent on the face of the Original Decision or otherwise existed on a balance of probabilities.

EPCOR Energy Alberta GP Inc. 2018-2020 Non-Energy Regulated Rate Tariff Application (Decision 22853-D01-2018)

Regulated Rate Tariff - Non-Energy

In this decision, the AUC considered EPCOR Energy Alberta GP Inc.'s ("EPCOR") 2018-2020 non-energy regulated rate tariff ("RRT") for service in the EPCOR Distribution & Transmission Inc. ("EDTI") and FortisAlberta Inc. ("Fortis") service territories.

The AUC approved EPCOR's forecast customer site counts, operating costs, corporate services costs, property taxes, hearing cost deferral account, and depreciation expense subject to certain directions which EPCOR was directed to address in a compliance filing.

The AUC approved EPCOR's terms and conditions effective October 4, 2018.

Forecast Revenue Requirement and Monthly Non-Energy Charges

EPCOR's applied-for non-energy RRT revenue requirements for the 2018 to 2020 test period are set out in Table 1 below:

Table: Forecast non-energy RRT revenue requirements for 2018 to 2020

Year	2018	2019	2020
Millions ($)	36.85	36.91	41.57

Table: Forecast monthly non-energy charges for 2018 to 2020

	2018	2019	2020
	$ per site per month		
Customer type			
Fortis service area			
Residential	5.48	5.54	6.28
Farm	4.99	5.01	5.70
Irrigation	3.53	3.34	3.83
Small commercial	5.89	6.15	7.05
Oil & gas	9.67	10.65	11.70
Lighting	5.40	5.42	6.13
EDTI service area			

Residential	5.40	5.44	6.17
Small commercial	4.87	4.88	5.59
Lighting	5.15	5.15	5.86

Customer Information System Project

EPCOR proposed a new customer information system ("CIS") to replace its existing customer billing (Utility Information System or UIS), and its relationship management (Customer Relationship Management or "CRM") systems, with a single integrated system. Subject to Board approval, EPCOR anticipated that the CIS project would commence on September 4, 2018, and take 18 to 24 months to complete.

The AUC approved the forecast costs related to the CIS project included in EPCOR's revenue requirement, on an interim refundable basis, finding that:

(a) the CIS project was required for the provision of utility service because the program would provide support to EPCOR's customer service and billing functions; and

(b) the timing of the CIS project was reasonable given that the existing information systems were at the end of their useful life.

The AUC directed EPCOR to:

(a) include a proposal to true-up its costs related to the CIS project as part of its next RRT non-energy application;

(b) confirm that EPCOR Utilities Inc. ("EUI") secured a fixed-price contract and to include a detailed update on the vendor selection process, the vendor selected, and the contracts signed with the selected vendor in its compliance filing to this decision; and

(c) include, in its compliance filing, a proposal for an asset usage fee that allocated CIS costs to the RRT, based on the functions necessary to serve RRT customers and then based on the forecast site counts.

Customer Service Consultant Costs

EPCOR's customer service consultants ("CSC") are the contact centre personnel who answer calls and respond to customer questions. The costs for this category include salaries and benefits, as well as related costs such as training, telephone, and supplies. EPCOR's forecast CSC costs, allocated to RRT for the test period were $2.86 million in 2018, $2.82 million in 2019, and $3.52 million in 2020. This represented an increase from an updated 2017 forecast of $2.68 million, which was higher than the AUC approved amount of $2.54 million for 2017.

The AUC accepted that experienced CSCs were needed to work on the CIS project because they had the best knowledge of the service requirements and existing processes and that new hires would be required to backfill positions. However, it was not clear to the AUC that this warranted an increase in CSC costs from past forecasts beyond an inflation adjustment.

The AUC noted that the service level agreement between EPCOR and EUI provided that EPCOR would apply an hourly fee for all hours worked, inclusive of fully burdened salaries. The AUC considered that if experienced CSCs were replaced by new hires because the experienced CSCs were required on the CIS project, then the costs for experienced CSCs would be removed from the CSC revenue requirement. Subsequently, these costs would be allocated to the CIS project to ensure there was no double counting for any amounts paid by EUI.

The AUC found that it was not reasonable for EPCOR to enter into a contract whereby its experienced employees provide services to another entity, unless the fees paid for those services at a minimum cover EPCOR'S cost of replacing those experienced employees.

Accordingly, the AUC directed EPCOR to remove any costs associated with additional training for new hires replacing any EPCOR staff, including CSCs, as well as any costs associated with decreased performance or efficiency resulting from those experienced resources being replaced by new hires, e.g., increased call-handling times.

Recovery of Mid-Term Incentive Program Costs

Participating EUI group management employees, including the management of EPCOR, were eligible for a mid-term incentive ("MTI") program. The MTI program was created in 2010 and applied only to senior management. It was set using two performance metrics:

- net income; and
- the compounded annual growth rate for property, plant, and equipment.

The AUC denied EPCOR's requested MTI program costs for 2018, 2019 and 2020. The AUC found that there was insufficient evidence that the MTI costs were required to provide Regulated Rate Options ("RRO") electricity services. Therefore, a change in the treatment of the costs of the MTI program was not warranted. EPCOR did not seek recovery of any of RRT's share of MTI costs in its 2014-2015 and 2016-2017 RRT applications.

Recovery of Business Development Costs

The AUC found that there was insufficient evidence to conclude that business development costs were required to provide RRO electricity services. Therefore, the AUC found that recovery of these costs was not warranted.

The AUC directed EPCOR, in its compliance filing, to exclude any business development costs for 2018, 2019 and 2020.

Bad Debt

The AUC approved the bad debt expense percentages for 2018-2020 as proposed in EPCOR's application. The AUC found that these percentages were consistent with EPCOR's previously approved bad debt expense methodology. The percentages for the rate class related to Fortis' oil and gas customers was also calculated consistently with EPCOR's methodology and, therefore, found to be reasonable.

Asset Retirement and Depreciation

The AUC denied EPCOR's proposal to reduce the depreciation period for its existing information management and customer relationship assets being replaced by the CIS.

The AUC recommended that when the date of replacement of the old assets with the new CIS program assets was known, EPCOR should file a proposal on how the net book value of the retiring assets should be treated for regulatory purposes.

Under-forecasting Site Counts

The AUC found that an adjustment to site counts was not warranted. The AUC directed EPCOR to include in its compliance filing, updated site count forecasts based on the most recently available site counts. The AUC acknowledged that as RRO prices reached the rate cap, a reasonable assumption was that some non-RRT customers may migrate back to RRT service and fewer customers would leave RRT service for competitive retail alternatives. However, the effect of the rate cap and any potential migration back to the RRO was uncertain. Given the implementation of a rate cap, the AUC found it reasonable for EPCOR to update its site count forecasts accounting for more recent actual data.

Oil and Gas Rate Increase

The AUC approved the increase in oil and gas monthly non-energy rates.

The AUC was satisfied that the increase in monthly non-energy charges for the oil and gas rate class was due to inclusion of a bad debt expense for this rate class. The AUC approved EPCOR's calculation of a bad debt forecast for the oil and gas rate class. With respect to oil and gas customers' total bill, this increase did not constitute rate shock because the increase was less than one percent.

Price Schedule and Terms and Conditions

The AUC directed EPCOR to file updated price schedules in its compliance filing that reflected the approved revenue requirement and other approvals granted by the AUC in this decision.

The AUC approved EPCOR's changes to its terms and conditions indicating the changes provided additional clarity regarding billing due dates and the disconnection process for non-payment.

Summary

The AUC approved EPCOR's forecast customer site counts, operating costs, corporate services costs, property taxes, hearing cost deferral account, and depreciation expense subject to certain directions which EPCOR was directed to address in a compliance filing.

The AUC approved EPCOR's terms and conditions effective October 4, 2018.

EPCOR Distribution & Transmission Inc. 2018-2019 Transmission Facility Owner Tariff Application (Decision 23165-D01-2018)

Revenue Requirement - Transmission Facility Owner - Tariff Application

In this decision, the AUC considered an application by EPCOR Distribution and Transmission Inc. ("EPCOR") requesting approval of its transmission facility owner ("TFO") tariff for the 2018-2019 test years.

The AUC did not approve the requested revenue requirement of EPCOR for the years 2018-2019. The AUC ordered EPCOR to refile its application by November 15, 2018.

EPCOR applied for various approvals associated with its TFO function for the 2018 and 2019 test years (the "TFO Application"). Specifically, EPCOR requested approval of:

(a) the transmission rates to be paid by the Alberta Electric System Operator ("AESO") for the use of EPCOR's transmission facilities over the test period;

(b) the TFO terms and conditions of service ("T&Cs");

(c) the continued use of the following transmission reserve and deferral accounts in the test period:

- (i) hearing cost reserve;
- (ii) self-insurance reserve;
- (iii) AESO directed projects deferral account;
- (iv) transmission property, business, and linear taxes deferral account; and
- (v) transmission short-term incentive ("STI") deferral account;

and

(d) placeholders related to capital structure and rate of return on equity ("ROE") for its transmission function.

The table below provides a summary of the updated forecast capital expenditures and capital additions for 2018 and 2019 compared to 2017 updated forecasts.

Forecast Capital Expenditures and Capital Additions for the Years 2017-2019

	2017 Updated Forecast	2018 Forecast	2019 Forecast
	($ million)		
Capital Expenditures (cap ex)	34.33	57.26	30.65
Capital Additions (cap add)	40.18	34.95	59.75

<u>Transmission O&M Costs</u>

The AUC approved the direct O&M forecast costs for 2018 and 2019, finding the test year forecasts for direct O&M to be reasonable.

EPCOR's operating costs are comprised of direct O&M costs, administrative and general ("A&G") expenses, and allocated corporate general and administrative expenses.

<u>Labour Related Costs</u>

The AUC approved:

(a) the addition of four full-time employees ("FTEs") transferred to transmission from the Master Overhead Pool ("MOP"), finding that these positions were transferred to transmission from a shared MOP cost category to ensure that their cost treatment more accurately reflected the work performed;

(b) the reclassification of the 2.5 FTEs related to management and supervision of substation field operations staff, finding that the overall FTE total never added up to more than 100 percent of the total FTE costs on a forecast basis and, therefore, there was no risk of double recovery; and

(c) the addition of 2.4 FTEs in 2019, finding these additions to be reasonable given the growth in rate base and the continued aging of EPCOR's fleet of assets.

However, the AUC directed EPCOR to remove the costs associated with 5.5 FTEs from the forecast revenue requirement, finding that EPCOR failed to sufficiently justify the increase in the number of O&M related FTEs.

Employee Compensation and Benefits

The AUC found that the mid-term incentive ("MTI") program and its costs were not required for utility service. The AUC denied the requested MTI program costs for 2018 and 2019.

Contractors, Other Escalation and Materials

The AUC found that EPCOR's proposed inflation factors for contractors, materials, and other costs were reasonable and, therefore, approved these costs as filed.

Administrative and General ("A & G") Expenses

EPCOR requested a forecast $5.12 million A&G expenses in 2018. However, the AUC observed that in its schedules, EPCOR requested a forecast of $7.98 million for A&G expenses in 2018, and did not provide an explanation with respect to this difference between the forecasts in the application and the schedules. The AUC found that the correct forecast was not known. Accordingly, the AUC directed EPCOR in its compliance filing, to provide the correct forecast for A&G expense and to reflect those correct amounts in its compliance filing and schedules.

Corporate Services Costs

The AUC denied EPCOR's proposal to include business development costs in its revenue requirement. The AUC determined that business development costs were not required for the provision of utility service.

Transmission Other Revenue Requirement Items

The AUC approved the forecast for transmission other revenue requirement items and the continuation of the Transmission Property, Business and Linear Tax Deferral Account. The AUC found EPCOR's methodology was consistent with previous applications approved by the AUC. Therefore, the AUC found the forecast costs to be reasonable.

Other Revenue Requirement Adjustments

The AUC found EPCOR's request to recover incurred costs for the project variances as an operating expense to be reasonable since the expenditures on this project were not incurred for the acquisition or construction of assets that would remain in rate base in future periods.

Rate Base

2018 Opening Rate Base

The AUC approved the 2015, 2016, and 2017 rate base additions as filed, for the purposes of determining the revenue requirement for the test period. The AUC directed EPCOR to update its 2018 opening rate base to reflect the 2017 actual amounts for the life cycle projects, which were initially estimated using a three-year average.

EPCOR requested approval of its opening 2018 net transmission rate base of $673.44 million. The table below shows a comparison of approved to actual closing rate base amounts for the prior test period, from 2015-2017.

Table: Transmission Rate Base 2015-2017

	2015	**2016**	**2017**
	($million)		
AUC Decision	654.25	662.26	659.92
Actual (or updated forecast)	655.21	670.75	674.86
$ over (under) AUC Decision to actual	0.96	8.43	14.94
% over (under)	0.15	1.27	2.26

Capital Additions

The AUC approved EPCOR's forecast capital expenditures and capital additions for the years 2018 and 2019 for the purpose of calculating the forecast revenue requirement in the test years, subject to the AUC's directions summarized below.

Substation Feeder Additions

This project was an ongoing project to install circuit breakers and current limiting reactors to meet requirements for new distribution feeders at transmission substations. New distribution feeders were required to ensure sufficient capacity was available for load growth. Work associated with thirteen new feeders was forecast for this test period.

The cost forecasts for the feeder addition projects were based on a bottom-up approach, which the AUC previously accepted as reasonable. While the selection of feeders to be added in a given period was based on load forecasts which inherently were uncertain, the AUC found that EPCOR's methodology for evaluating load requirements and tracking design load exceedances was reasonable.

The total number of feeder additions in the test period was unclear: The application stated thirteen feeder additions with two of those serving specific large customers and the remaining 11 serving regional load; however, the list of feeder additions only included nine feeders.

The AUC directed EPCOR to provide a complete list of feeders to be added in the test period (i.e. 2018 and 2019 only), with the substation clearly associated to each listed. The AUC also directed EPCOR to provide an update to the actual or forecast in-service date of each feeder addition, and an updated capital addition forecast for each.

<u>Non-AESO Directed Growth Projects and Performance Improvement Projects</u>

Garneau Switchgear Replacement Project

The AUC approved the project given that the costs for the Garneau switchgear replacements were fully-funded through the customer contributions from the University of Alberta ("U of A"). The AUC found the project and the costs recovery proposed were reasonable.

The AUC accepted EPCOR's submission that the Garneau switchgear replacement would not be undertaken in 2019, but for the U of A's request. EPCOR Distribution & Transmission Inc.'s ("EDTI") transmission function determined that the project was not currently required to meet distribution load requirements in the area, nor was it likely required until approximately 2028, and neither the AESO nor EDTI's distribution function requested that this project be undertaken during the test period.

The AUC found that any reduced operations and maintenance costs associated with the new switchgear in 2019 did not justify the U of A's proposed reduction of its customer contribution. This finding was also supported by evidence that the U of A comprised 85.5 percent of the Garneau substation peak load in 2017.

The U of A indicated that it would request a refund when the switchgear would normally be replaced due to load constraints or asset condition in 2028. The AUC approved EPCOR's proposal to repay the U of A the net book value of the switchgear when the substation load reaches the level at which it would normally be replaced. The AUC found that this proposal would balance the costs paid by the customer and Alberta ratepayers over the life of the asset, especially given that this project was a customer directed project.

<u>Lifecycle Replacement Projects</u>

The AUC accepted EPCOR's evidence that 72RS5 oil-filled pipe type cable (the "72RS5 cable") could no longer operate at the required rating, had reached the end of its useful life and required replacement. The AUC accepted EPCOR's proposed alternative of replacing the 72RS5 cable with an aerial line as being the lowest cost and a technically sufficient solution for the purposes of forecasting capital costs for the 2018-2019 revenue requirement. The AUC noted that the design and route were subject to AUC review in the facility application.

The AUC reviewed the cost forecast evidence and found the magnitude of the forecast capital expenditures and additions were reasonable given the project scope and location.

Rossdale Medium Voltage Switchgear Addition

The AUC was concerned by the cost increase in this project attributed to the engineering consultant error. There was insufficient information to determine whether EPCOR took all reasonable steps to mitigate the cost increase or recover damages. The AUC considered that additional information was required to determine whether the cost increases were attributable to the design consultant error. The AUC directed EPCOR to remove the $1.07 million associated with the engineering consultant design deficiencies from the 2018 capital additions.

Return on Rate Base

Given that EPCOR's application had already incorporated an ROE and deemed equity ratio of 8.5 percent and 37 percent, respectively, for the years 2018 and 2019 consistent with the AUC's findings in Decision 22570-D01-2018, there was no requirement for EPCOR to update its applied-for ROE and deemed equity ratio. Accordingly, the AUC approved EPCOR's 2018-2019 ROE and deemed equity ratio on a final basis, as filed.

Cost of Debt

The AUC found that EPCOR's forecast interest expense calculation on its long-term debt was consistent with the application of the mid-year convention. The AUC agreed with EPCOR's explanation that the effect of applying the mid-year convention to the determination of its interest expense was that all debt was assumed to have been issued mid-year and, thus, attracted six months of interest expense in both the year the debt was issued and the year in which the debt matured.

Determination of the Forward Curve Interest Rates

The AUC found that forward curve yields derived using the most recent data available for the month of June was a reasonable approach to determining EPCOR's cost of debt and was consistent with the AUC's previous findings. Therefore, the AUC based its determination on the average of the June 1 to June 6, 2018, one- and two- year forward curve fields on a 30-year Government of Canada bond. The average one-year yield was 2.34 percent, and the average two-year yield was 2.35 percent.

The AUC directed EPCOR to reflect 2018 and 2019 forward curve interest rates in the amounts of 2.34 percent and 2.35 percent, respectively.

Determination of the Credit Risk Premium (or Credit Spread)

EPCOR proposed a credit risk premium of 1.50 percent based on the use of the average spread of a group of comparable utilities, which included FortisAlberta, FortisBC, Nova Scotia Power. The AUC found TransCanada and Westcoast, all of which were rated A (low) by DBRS (originally known as "Dominion Bond Rating Service").

The AUC considered the range of credit spreads of Westcoast and TransCanada compared with the range of credit spreads among the two Fortis companies and Nova Scotia Power, and found that the divergence between the five companies was at an unacceptable level for comparative use. For this reason, the AUC found that Westcoast and TransCanada were not close comparators for the purposes of determining EPCOR's credit risk premium.

The AUC found that the determination of EPCOR's credit risk premium should be based on the average of the credit spreads of FortisAlberta, FortisBC and Nova Scotia Power (the "Approved Credit Risk Premium"). The AUC considered these companies to be equivalent in risk to EPCOR because FortisAlberta, Fortis BC and Nova Scotia Power were all rated A (low), and because the range of the lowest to highest credit risk spreads was found to be within an acceptable level compared to that of Westcoast and TransCanada.

The AUC directed EPCOR to apply the Approved Credit Risk Premium of 1.25 percent for the years 2018 and 2019 in its compliance filing.

Depreciation and Amortization

The AUC was of the view that the rationale justifying the Alberta Energy and Utilities Board's decision to approve EPCOR's depreciation methodology at the outset of EPCOR's regulation under the AUC's predecessor remained valid.

The AUC was satisfied with EPCOR's proposal to adopt AltaLink's currently approved average service lives for EPCOR's similarly constructed ISO Rule 502.2 related assets. EPCOR proposed to increase the average service lives of six other accounts that were designed and constructed under the functional specifications of ISO Rule 502.2.

The AUC directed EPCOR to confirm whether it intended to mirror the 65-year average service life of AltaLink's conductors and devices for its Heartland asset, or if EPCOR was satisfied with an average service life of 67 years as proposed.

The AUC approved:

(a) EPCOR's proposal to refund the Heartland-related reserve surplus over a period of two years, being the years 2018 and 2019;

(b) EPCOR's proposed changes to the average service lives of eleven asset accounts; and

(c) EPCOR's transmission working capital forecast for 2018-2019, subject to any required adjustments.

Order

The AUC directed EPCOR to refile its application to reflect the findings, conclusions and directions in this decision.

AUC Bulletin 2018-14 Practice Advisory and Procedural Change for Oral Argument in Facility Proceedings

Oral Argument - Notice

In this bulletin, the AUC acknowledged that the requirement for oral argument is not always communicated by the AUC in advance of the start of a hearing, which stakeholders indicated can lead to inefficiencies in process and time pressures to conclude the hearing within the allotted time.

Section 47.1 of AUC Rule 001: *Rules of Practice* provides that argument must be in the form directed by the Commission. Section 2.5 of Rule 001 deals directly with time limits and states that the AUC may set time limits for doing anything provided for in the rule.

The AUC implemented a procedural change for facility proceedings involving an oral hearing. In most circumstances where the AUC anticipates prior to the start of an oral hearing that oral argument will be required, it will provide advance notice to parties and may also set time limits on oral argument. The AUC anticipates that timely notice will bring focus to argument, streamline proceedings and reduce costs while ensuring parties have a fair opportunity to be heard.