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LAW CHAMBERS

ENERGY REGULATORY REPORT

Regulatory Law Chambers *is a Calgary-based boutique law firm dedicated to excellence in energy regulatory matters. We have expertise in oil and gas, electricity, including renewable energies and commercial matters, tolls and tariff, compliance and environmental related matters. We frequently represent clients in proceedings before the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC"), the National Energy Board ("NEB"), all levels of the Courts, and in energy related arbitrations and mediations.* ***Our advice is practical and strategic. Our advocacy is effective.***

This monthly report summarizes matters under the jurisdiction of the AER, the AUC and the NEB and proceedings resulting from AER, AUC and NEB decisions. For further information, please contact Rosa Twyman at Rosa.Twyman@RLChambers.ca or John Gormley at John.Gormley@RLChambers.ca.

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ALBERTA ENERGY REGULATOR

Suncor Energy Inc. Tailings Management Plan and Operation Amendment Applications (Decision 20170317A)
Tailings Management Plan – Water-capping – Directive 085

In April 2016, Suncor Energy Inc. ("Suncor") filed an application (the "TMP Application") requesting that the AER approve its proposed tailing management plan for new and legacy fluid tailings associated with the Suncor base plant (the "Proposed TMP"). Suncor also filed a concurrent related application requesting amendments to previous approvals affected by Suncor's Proposed TMP (the "Amendment Application").

The Amendment Application described the construction, operation, and reclamation and closure modifications to Suncor's mine, tailings, dedicated disposal areas, and reclamation and closure plans.

The AER denied both the TMP Application and the associated Amendment Application (the "Applications") on the basis that the Proposed TMP did not satisfy the requirements of the *Lower Athabasca Region: Tailings Management Framework for the Mineable Athabasca Oil Sands* (the "Lower Athabasca TM Framework") or *Directive 085: Fluid Tailings Management for Oil Sands Mining Projects* ("*Directive 085*").

Water-capping

The AER noted that *Directive 085* requires a TMP to describe the risks, benefits, and trade-offs associated with tailings treatment technologies; and to describe the environmental risks and how they will be managed during operation, reclamation, and closure.

The AER found that the Proposed TMP did not provide adequate information regarding environmental effects and mitigations measures during operation, reclamation, and closure stages. The AER found that the Proposed TMP provided high-level information on the benefits and trade-offs of its technologies, but water-capping was not included in the comparison.

The AER found that Suncor provided insufficient information to allow the AER to conclude that the water-capping technology – a new and unproven technology – will result in an aquatic ecosystem in the time predicted. Therefore, the AER held that the Proposed TMP did not meet the requirements of *Directive 085*.

Alternatives

The AER noted that both the Lower Athabasca TM Framework and *Directive 085* require a tailings management plan to consider alternatives where water-capped fluid tailings technologies are proposed, given that water-capping is considered an unproven technology.

The Proposed TMP recommended that the decision to employ water capping or solid capping be made in 2039, 6 years after the expected life of the mine.

The AER found that the Proposed TMP did not provide adequate information on how the in-pit terrestrial landform would be constructed.

The AER noted that timelines for reclamation of the terrestrial option are 150 years or more. The AER found that this would be delayed by a 2039 decision milestone, and is significantly longer than the 30 year timeline associated with the proposed use of water-capping technology.

Deficient RTR Performance Criteria

Directive 085 requires a TMP to include ready-to-reclaim ("RTR") criteria to track the performance of the treated fluid tailings during depositing operations to ensure that the deposit can be reclaimed as predicted. RTR criteria must address a deposit's physical properties and environmental effects. Tailings deposits with higher uncertainty or more complexity may require more criteria.

The AER found that the Suncor failed to establish that its RTR criteria would ensure that lands affected by deposits can be reclaimed as predicted. The AER also found that Suncor failed to provide RTR criteria addressing potential effects the deposits may have on the environment or future reclamation.

Insufficient Information

The AER found that Suncor did not provide adequate information as follows:

(a) Plans to reduce uncertainties with:

  (i) the deposits, the types of mitigation proposed and associated challenges for their implementation, or the triggers for initiating their implementation; and

  (ii) the duration to operate pollution prevention and mitigation measures and the consideration of this duration in the environmental risk and trade-offs assessment; and

(b) Evidence to demonstrate assurance of progressive reclamation of tailings ponds as shown in the progressive reclamation status maps.

Decision and Direction

The AER denied the Applications, without prejudice to future Suncor applications. The AER directed Suncor to file a new fluid tailings management plan application and any additional amendment applications required to support changes to the approved project.

Request for Regulatory Appeal by Braun Land Owners (Appeal No. 1869031)
Regulatory Appeal – Denied – Eligible Person Definition

In this decision, the AER considered the Braun Land Owners Group's (the "Landowners") regulatory appeal request under section 38 of the *Responsible Energy Development Act* (the "*REDA*") for a regulatory appeal of an AER decision approving Penn West Petroleum Limited's ("Penn West") enhanced recovery scheme application (the "AER Decision").

Specifically, in the AER Decision, the AER issued an approval, pursuant to the *Oil and Gas Conservation Act*, for Penn West's proposed enhanced recovery of oil by gas injection and waterflood in the Blairmore Pool in the Armisie Field (the "Approval"). The injection was proposed to be conducted through the main existing well.

The AER denied the Landowners' request for a regulatory appeal, on the grounds that the Landowners group members did not meet the definition of "eligible person" under *REDA* section 36.

Preliminary Issue

One of the conditions of the Approval required injection to commence into the well(s) within three months of the date of the Approval (the "Commencement Condition").

The Landowners submitted that the Approval had expired since Penn West did not begin injections within the 3-month period required by the Commencement Condition. The Landowners argued that the request for regulatory appeal should be closed as the Approval had expired.

The AER noted that the Commencement Condition did not state that the Approval expires if injection does not commence within the specified time. The AER found that the Approval did not expire as a result of not meeting a condition. Therefore, since the Approval had not expired, the AER went on to consider the Landowners' request for regulatory appeal.

Request for Regulatory Appeal under *REDA* s 38

The applicable provision of *REDA* regarding regulatory appeal requests is contained in section 38(1), which states:

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

The term "eligible person" is defined in section 36(b)(ii) of the *REDA* to include: "a person who is directly and adversely affected by a decision [made under an energy resource enactment]."

Reasons for Decision

The AER held that the Approval is an appealable decision, as the decision was made under the *Oil and Gas Conservation Act*, an energy enactment, without a hearing.

The AER noted that the well for which the Approval was issued is not located on lands owned by the Landowners nor are the Landowners mineral rights holders in the area of the Approval. The AER noted that in issuing an enhanced recovery approval, it considers whether the subsurface characteristics of the reservoir are suitable for enhanced recovery operations. The AER stated that the Approval did not affect any surface rights or authorize activities that could impact the surface.

The AER found that the enhanced recovery scheme would eliminate the potential for surface emissions associated with Penn West's oil and gas production in the area, which is expected to decrease existing potential surface impacts.

Disposition

Given the above, the AER found that the Landowners had not established that they may be directly and adversely impacted by the AER Decision issuing the Approval. The AER held that the Landowners are not an "eligible person" under *REDA* section 38 and therefore dismissed the appeal request pursuant to *REDA* section 39(4).

Procedural Decision re Aboriginal Requests to Participate in Hearing of Rigel Project Applications
Standing – Aboriginal Groups

On January 30, 2017, the AER issued a notice of hearing of three applications (the "Applications") associated with Prosper Petroleum Ltd.'s ("Propser") Rigel Project (the "Project").

The following aboriginal groups filed requests to participate ("RTP"):

- Fort McKay First Nation ("FMFN");
- Fort McKay Métis ("FM Métis");
- Athabasca Chipewyan First Nation ("ACFN");
- Fort Chipewyan Métis Local 125 ("FCML 125")
- Fort McMurray Métis Local 1935 ("FMML 1935"); and
- Mikisew Cree First Nation ("MCFN").

In this decision, the AER granted intervener standing to FMFN, FM Métis and MCFN. The AER denied standing to ACFN, FCML125 and FMML 1935.

Right to Participate under *REDA* Section 34

Section 34 of the *Responsible Energy Development Act* ("*REDA*") states that "a person who may be directly and adversely affected by the application is entitled to be heard at the hearing".

AER Grants FMFN Request to Participate

The AER found that the proximity of the FMFN's Moose Lake Reserves to the Project demonstrate that FMFN could be directly and adversely affected by an AER decision regarding the Project. [The AER did not specify that distance.]

FM Métis

In accepting the FM Métis witness Ernst Treblay's affidavit regarding potential impacts to FM Metis trappers and trap lines, the AER found that members of the FM Métis conduct traditional activities in areas which may be impacted by the Project.

The AER held that the FM Métis may be directly and adversely affected and therefore granted standing to the FM Métis.

MCFN

The AER found that MCFN provided sufficient information in its RTP to demonstrate that its use of and relationship to the Moose Lake area may be directly and adversely affected by a decision to regarding the Project

The AER noted that MCFN included in its RTP the following information:

- That there are family burial areas around Moose Lake;
- That Moose Lake holds spiritual importance for the community; and
- That Moose Lake is part of a traditional route for MCFN members.

The AER granted MCFN standing to participate in the hearing as a full participant to address specific impacts of the Project on MCFN's Aboriginal rights and traditional land use.

ACFN

The AER noted that while the ACFN's submissions were relatively comprehensive, nowhere in them did ACFN state that they wanted to participate in the hearing. Nor did ACFN describe the nature and scope of their intended participation.

The AER noted that it had contacted ACFN and advised, both by phone and in writing, that if ACFN intended to participate in the hearing it should refer to the AER Rules of Practice and file a RTP by February 28, 2017.

ACFN filed nothing further. As a result, the AER found that ACFN had not met the requirements for filing a RTP. The AER therefore denied standing to ACFN.

FCML 125

The AER noted that FCML 125 provided no maps or other information regarding the location of FCML 125 member activities. The AER noted that the Project area is outside of the Government of Alberta 160 km harvesting radius for the FCML 125.

The AER held that FCML 125 did not provide information to establish that there was a sufficient degree of connection between the Project and FCML 125's activities to conclude that FCML 125 may be directly and adversely affected by an approval of the Applications.

The AER also addressed the statement in the FCML 125 request to participate, that FCML 125 intended to file a question of constitutional law relating as to whether the "duty to consult [was] not carried out by proponent or ACO".

The AER noted that *REDA* section 21 states that the AER has no jurisdiction with respect to assessing the adequacy of Crown consultation.

The AER held that the type of constitutional question proposed by FCML 125 was not within the AER's jurisdiction to consider. The AER stated that granting FCML 125 the right to participate to pose such a question would be of no assistance and would only serve to delay the proceeding.

FMML

In its February 28, 2017 letter to the AER, FMML stated it is "not making a request to participate and become a 'participant' in the hearing". Notwithstanding that statement, FMML requested the right to present a brief oral statement of 15 – 20 minutes and to file a brief written submission and traditional land use information.

The AER found that while FMML's letter referenced two trappers, it provided no information to establish whether those trappers or other members of the FMML community carry out activities that might be affected by a decision on the Applications.

The AER found that FMML's request to provide a written and an oral submission was effectively a request to be a participant with full participatory rights. For the reasons given above, the AER held that FMML was not entitled to participate in the hearing, including on the limited basis proposed.

ALBERTA UTILITIES COMMISSION

Direct Energy Regulated Services Application for Review of Decision 21568-D01-2016: Preliminary Question (Decision 22282-D01-2017)
Review Application – Granted – Grounds to Review

Background

In this decision, the AUC had to decide whether to grant an application filed by Direct Energy Regulated Services ("DERS") requesting a review and variance of Commission Decision 21568-D01-20161 (the "Original Decision").

The Original Decision addressed an application from DERS for approval of its 2012-2016 default rate tariff ("DRT") and regulated rate tariff ("RRT") which had been filed pursuant to Commission directions set out in Decision 2957-D01-2015.

DERS's review application concerned findings in the Original Decision regarding the requirement that DERS pay interest in accordance with AUC Rule 23: *Rules Respecting Payment of Interest* ("*Rule 023*"). *Rule 023* provides for the payment of interest on adjustments of utility rates, tolls, charges or other costs upon approval by the AUC.

In this decision considering the preliminary question as to whether there were grounds to review the Original Decision, the AUC found that there were such grounds, for the reasons summarized below.

AUC Consideration of Review and Variance Applications

The AUC explained that it has discretionary authority to review its own decisions under section 10 of the *Alberta Utilities Commission Act* ("*AUCA*"). The AUC's process regarding its consideration of an application to review one of its decisions is set out in AUC Rule 016.

The review process has two stages. In the first stage, a review panel must decide whether there are grounds to review the original decision. If the review panel decides that there are grounds to review the decision, it moves to the second stage of the review process, where the AUC holds a proceeding to decide whether to confirm, vary, or rescind the original decision.

Section 6(3) of Rule 016 describes the circumstances in which 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."

Review Panel Guiding Principles

In AUC Decision 2012-124, the AUC addressed the role of a review panel and concluded that it should apply the following principles to its consideration of review applications before it:

- First, decisions of the AUC are intended to be final; the AUC's rules recognize that a review should only be granted in those limited circumstances described in Rule 016.
- Second, 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 proceeding.
- Third, the review panel's task is not to retry the application based upon its own interpretation of the evidence nor is it to second guess the weight assigned by the hearing panel to various pieces of evidence. Findings of fact and inferences of fact made by the hearing panel are entitled to considerable deference, absent an obvious or palpable error.

Grounds for Review

DERS submitted that the hearing panel erred in fact, law or jurisdiction, raising a substantial doubt as to the correctness of the decision by:

(a) Reaching a decision that was not supported by the evidence and was made in breach of the duty of procedural fairness;

(b) Failing to interpret and apply Rule 23 correctly; and

(c) Assuming facts not in evidence and failing to properly consider facts in evidence.

Procedural Fairness

DERS submitted that it was denied the opportunity to know the case it had to meet, because it had no reason to believe that the AUC was going to assess whether it should have applied for an interim rate decrease, or that its failure to do so would warrant an award of interest pursuant to *Rule 023*.

The hearing panel found the following facts to be significant in its evaluation regarding whether a material error arose in the Decision:

(a) DERS sought an increase in rates beyond the amounts it was recovering under the interim rates;

(b) The original panel found that *Rule 023* interest will accrue unless an applicant actively takes steps to ensure that there are not significant differences between interim and final rates, and therefore no rate shock; and

(c) The first time DERS became aware of the issue of the awarding of *Rule 023* interest was in information requests from the AUC to DERS.

Given that DERS did not request to change its interim rates, the review panel found that DERS could not have anticipated that submissions on *Rule 023* were required.

On this point, the review panel noted that DERS was unable to identify any precedent where similar findings had been made. In other AUC decisions in which interest has been either awarded or rejected, the applicant utility requested changes to interim rates and the issue of whether interest should be awarded was clearly an issue before the AUC.

The review panel held that DERS has demonstrated on a balance of probabilities that it was not given an opportunity to present its case regarding whether an award of interest should have been granted.

Moreover, the review panel held that additional submissions from DERS on that issue could lead the AUC to materially vary the findings in the Original Decision regarding the application of *Rule 023*.

Decision

The review panel found that DERS demonstrated that an error was either obvious on the face of the Decision, or otherwise existed on a balance of probabilities. Further, the review panel found that there was a reasonable possibility that this error could lead the AUC to materially vary or rescind the Original Decision.

Accordingly, the review panel held that DERS satisfied the requirements for a review of the findings in paragraphs 47, 48 and 50 of the Original Decision.

Having found that DERS met the first stage of the review and variance application (also referred to by the AUC as the “Preliminary Question”), the AUC allowed the review to proceed to stage two.

The AUC stated that it will issue process and scope directions for the second stage in due course.

ENMAX Power Corporation Distribution Terms and Conditions Compliance Filing (Decision 22141-D01-2017)
Terms & Conditions – Compliance Filing

In this decision, the AUC considered ENMAX Power Corporation’s (“ENMAX”) compliance filing to Decision 22032-D01-2016 regarding ENMAX’s proposed changes to its distribution terms and conditions (“T&Cs”).

Background

On December 18, 2015, ENMAX filed an application with the AUC for approval of a performance-based regulation (“PBR”) plan for its electric distribution services for the period of January 1, 2015 to December 31, 2017 (the “Original Application”). However, by letter dated January 20, 2016, ENMAX advised that it had met with the Consumers’ Coalition of Alberta (“CCA”) and the Office of the Utilities Consumer Advocate (the “UCA”), and that all parties were willing to explore a negotiated settlement agreement (“NSA”) with respect to the Original Application.

On May 12, 2016, ENMAX filed for approval its negotiated settlement agreement (“NSA”) with the CCA and UCA (the “NSA Application”). The NSA did not include the X factor component to be used in the PBR rate-setting formula, which was considered by the Commission separately.

In Decision 21149-D01-2016, the AUC approved the NSA between ENMAX and consumer groups with respect to ENMAX’s proposed 2015-2017 PBR plan (the “NSA Approval”). Because the X factor component of the PBR rate-setting formula was not part of the NSA, in the same decision the AUC also approved an interim X factor.

On September 28, 2016, ENMAX filed an application with the AUC requesting approval of additional changes to its T&Cs.

In that application (the “T&Cs Application”), ENMAX requested approval of changes to several sections of its T&Cs and to the quantum of fees in its distribution tariff schedules. ENMAX attached to the T&Cs Application emails from the CCA and the UCA confirming that, as part of the NSA negotiations, both the CCA and the UCA agreed to the proposed T&Cs changes, with the exception of item 15 of the distribution tariff fee schedule.

In an information request response, ENMAX clarified that it included the proposed T&Cs changes as part of the Original Application, but not as part of the NSA Application. ENMAX stated that it had interpreted the wording of paragraph 38(g) of the NSA Approval as approving the proposed T&Cs changes.

Given that the proposed T&Cs changes were not filed as part of the NSA Application, the AUC did not consider these proposed changes in its review of the NSA Application or approve them in the NSA Approval.

On October 21, 2016, the AUC issued Decision 22032-D01-2016, which considered ENMAX’s proposed changes to its T&Cs. In that decision, the AUC directed ENMAX, in a compliance filing, to:

(a) File a revised T&Cs application, to be considered under a new proceeding, with supporting explanations regarding the proposed changes; and

(b) Refund customers’ fees that were found to be not approved in the NSA Approval and in excess of the fees in the ENMAX fee schedules approved in Decision 2013-247.

On November 10, 2016, in response to directions set out in Decision 22032-D01-2016, ENMAX filed its compliance filing (the "T&Cs Compliance Filing"). That T&Cs Compliance Filing is the subject of this Decision 22141-D01-2017 summarized below.

Force Majeure Clause

ENMAX proposed to include the following addition in Section 5.5.1 of its T&Cs:

> If an event or circumstance of Force Majeure occurs that affects EPC's ability to provide any service under these Terms and Conditions, including Connection Services or other interconnection to its electric distribution system or Distribution Access Service, EPC's obligations and responsibilities hereunder and under any agreement relating to such services, so far as they are affected by the Force Majeure or the consequences thereof, shall be suspended until such Force Majeure or the consequences thereof are remedied and for such period thereafter as may reasonably be required to restore the services. All ***applicable*** charges in the EPC Distribution Tariff Rate Schedule, will continue to be payable, during the period in which EPC claims relief by reason of Force Majeure [emphasis added by AUC].

ENMAX submitted that the proposed change was "modified for clarity."

The AUC found that it was unclear, based on a plain reading of ENMAX's T&Cs, precisely which charges ENMAX would continue to collect from customers, notwithstanding an interruption in service. The AUC expressed concern that this lack of clarity could be confusing to customers.

Accordingly, the AUC directed ENMAX to propose changes to its T&Cs and rate schedules to provide greater clarity and transparency with respect to a customer's liability in the event of a *force majeure*.

The AUC approved the proposed language on an interim basis. In the event of a *force majeure*, the AUC directed that:

(a) ENMAX would apply the provision in its T&Cs such that the "applicable charges" associated with any event of *force majeure* would be the same as the "minimum charges" as described in either EPCOR's or Fortis' T&Cs;

(b) ENMAX would not charge a customer any consumption-based charges (system usage or variable charges) in the "applicable charges" imposed during an event of *force majeure* which resulted in the interruption; and

(c) the interim approval would remain in effect until ENMAX applies for new wording in its next T&Cs application or as part of the next annual PBR rate adjustment filing, whichever comes first.

Maximum Investment Levels

ENMAX applied for increases to its maximum investment levels ("MILs"), and that MILs be escalated annually by the I-X mechanism and be effective January 1, during the PBR term. ENMAX also proposed that the fee schedule be escalated using the same methodology.

The AUC noted that in its calculations, ENMAX included a "catch up" component calculated as a dollar difference between the 2015 MILs and special fees in place for that year and the amounts that would have been effective if the 2015 I-X indexing was applied for that year. The AUC rejected ENMAX's proposed inclusion of such a "catch up" component.

The AUC noted that it approved ENMAX's MIL and fee schedule amounts in Decision 2014-347, on a final basis effective January 1, 2015 (the "2015 Approved T&Cs"). The 2015 Approved T&Cs remained in place until the AUC approved changes to ENMAX's T&Cs on an interim basis in Decision 22032-D01-2016.

The AUC held that ENMAX's proposed "catch up" component would constitute prohibited retrospective ratemaking.

Refund of Fees in Excess of Approved Fee Schedule

In Decision 22032-D01-2016, the AUC directed ENMAX to refund the customers charged fees, which the AUC found to be in excess of the approved distribution tariff fee schedules.

ENMAX provided a list, by type of distribution tariff fee or investment policy charge, with associated dates, of all transactions and amounts charged in error and subsequently refunded between these dates.

The AUC found that from the information ENMAX provided, ENMAX had satisfactorily complied with this direction.

Complaint by Mr. Baux Regarding Metered Service Horse Creek Water Services Inc. (Decision 22318-D01-2017)
Complaint – Terms & Conditions – Water Meter Costs

Complaint Application

In the complaint application, Mr. Baux submitted that Decision 2011-061 did not stipulate that pre-existing non-metered sites must be metered, and that the changes to the T&Cs approved in Decision 2011-061 related to new services and not existing services.

The AUC did not agree with this interpretation.

The AUC found that Decision 2011-061 did not contain any directions as to who should have been included or exempted from the flat rate service. Rather, the primary purpose of the proposed amendments to the T&Cs approved in Decision 2011-061 was the elimination of the flat rate service altogether.

The AUC found that this in turn, meant that all current and future customers were required to have a meter.

Based on these findings, the AUC concluded that Mr. Baux is required to have a meter.

Timing and Cost Responsibility

The AUC noted Mr. Baux's statements that he negotiated with HCWS and received an offer to "half the cost of a meter install to $400."

The AUC considered that Mr. Baux and HCWS should share equally in the total cost of the water meter installation up to $800. The AUC ruled that any amounts over $800 will be the responsibility of Mr. Baux.

The AUC also directed that Mr. Baux should have a meter installed within 30 days of the date of this decision.

EPCOR Distribution & Transmission Inc. April 1, 2017 Recovery Rider J (Decision 22419-D01-2017)
Recovery Rider J - Rate Shock Mitigation

On February 15, 2017, EPCOR Distribution & Transmission Inc. (EPCOR) submitted an application (the "Application") to the AUC requesting approval to collect, through a rate Rider J (referred to as the "Recovery Rider J"), the refunded amounts relating to a rate shock mitigation strategy previously approved in Decision 21979-D01-2016, which considered EPCOR's 2017 annual rates under performance-based regulation ("PBR") effective January 1, 2017.

Background: Rate Shock Mitigation & Rate Refund Rider J

On December 23, 2016, the AUC issued Decision 21979-D01-2016, approving EPCOR's 2017 annual rates under performance-based regulation (PBR) effective January 1, 2017.

In that decision, the AUC noted there was a potential that some customers would experience rate shock when the 2017 rates went into effect. Accordingly, the AUC found that a rate mitigation strategy was warranted.

The AUC accepted EPCOR's proposal to employ a refund through its Rider J to limit total bill impacts to 10 per cent or less for all rate classes (referred to as "Refund Rider J"). The AUC directed EPCOR to implement the Refund Rider J from January 1, 2017 to March 31, 2017.

To allow EPCOR to collect the same amount of distribution revenue in the 2017 calendar year as would have otherwise been collected had the refund not been implemented, the AUC allowed EPCOR the opportunity to request an additional rate change effective April 1, 2017.

To that effect, the AUC directed EPCOR to file an application by February 15, 2017, to reverse the refund in Rider J and collect the refunded amounts over the period of April 1, 2017 through December 31, 2017.

Recovery Rider J Application

In the Application, EPCOR explained that Rider J, effective from January 1, 2017 to March 31, 2017 (referred to as "Combined Rider J"), was composed of two separately approved rider components, namely the "Approved Rider J" and "Refund Rider J."

The AUC found that the total effect of the Refund Rider J and the Recovery Rider J is that EPCOR would receive the same revenue amount as would have otherwise been collected had the Refund Rider J not been implemented. Accordingly, the AUC found that EPCOR's calculations in support of the Recovery Rider J and the Combined Rider J to be reasonable.

Decision and Order

The AUC held that the Recovery Rider J, as applied for, was a fair means of collecting the previously refunded amounts over a reasonable time period.

Accordingly, the AUC approved the Recovery Rider J and the associated Combined Rider J, as filed.

FortisAlberta Inc. April 1, 2017, Performance-Based Regulation Rates (Decision 22415-D01-2017)
PBR Rates – Rate Shock Mitigation

Background

On December 23, 2016, the AUC issued Decision 21980-D01-2016 with respect to Fortis Alberta Inc.'s ("Fortis") 2017 annual performance based regulation ("PBR") rates. To address potential rate shock concerns, the AUC also approved a rate shock mitigation strategy in that decision, whereby Fortis' PBR-related rates would be maintained at the 2016 levels for residential customers. The Commission considered the bill impacts for the remaining rate classes to be acceptable without mitigation.

To allow Fortis to collect the same amount of distribution revenue in the 2017 calendar year as would have otherwise been collected had the proposed PBR rate increases been implemented on January 1, 2017, the AUC allowed Fortis to apply for an additional rate change effective April 1, 2017, for Fortis' residential customers.

Application

Fortis calculated its 2017 PBR rates effective April 1, 2017, using the approved PBR formula components and added a true-up factor to recover the full 12 calendar months of revenue over nine months.

Fortis' applications stated that the resulting PBR rate proposed by Fortis to be in effect April 1, 2017, increased by 3.0 per cent for typical residential customers from March to April 2017.

AUC Findings and Decision

The AUC noted that in past decisions, it has generally considered 10 per cent to be the threshold potentially indicative of rate shock.

The AUC observed that Fortis' estimated bill impacts of 3.0 percent did not include the effect of the quarterly AESO DTS deferral account rider also effective April 1, 2017 (the "Q2 AESO DA Rider").

However, the AUC found that the total bill impact for a typical residential customer remained below 10 percent, even with the inclusion of the Q2 AESO DA Rider. The AUC found that the impact to residential customers falls within a reasonable range and is unlikely to result in rate shock.

Accordingly, the AUC approved Fortis' 2017 PBR rates as filed, effective April 1, 2017.

Alberta Electric System Operator 2015 Deferral Account Reconciliation (Decision 21735-D02-2017)
AESO Deferral Account Reconciliation – Retroactive/Retrospective Ratemaking

The Alberta Electric System Operator ("AESO") applied for approval of its 2015 deferral account reconciliation ("DAR") application. (the "DAR Application")

In the DAR application, the AESO requested that the AUC approve the current deferral account amounts on an interim and refundable basis, in order to settle deferral account amounts immediately with market participants.

In this Decision, the AUC explained that the AESO's deferral account reconciles variances arising from the actual costs the AESO incurs in providing system access service and the forecast amounts the AESO recovers in rates charged to customers.

The AUC approved the DAR Application as filed and dismissed the Primary Services Group's (the "PS Group") request for relief to adjust the Rate DTS deferral account allocation back to 2008, for the reasons summarized below.

PS Group Concerns

The DAR Application was opposed, in part, by the PS Group. The PS Group submitted that the deferral account methodology used by the AESO was inconsistent with the approved tariff.

The PS Group submitted that the AESO's methodology allocated a proportion of point of delivery charges to primary service credit eligible customers in excess of what those customers were responsible for under the approved ISO tariff.

Specifically, the PS Group submitted that the AESO's DAR methodology caused an increase in the amount due for Rate DTS customers' point of delivery charge, without offsetting that increase for customers who are eligible for the primary service credit as a result of owning their own substation facilities. The PS Group submitted that as a result of the AESO's methodology, primary service credit eligible customers had been paying for substation related costs not caused by those customers.

Change to Approved Tariff

The AUC dismissed the PS Group's requested relief on the basis that granting such relief would constitute a change in the approved tariff allocation methodology and that it was not a calculation error, as the PS Group submitted. As such, the AUC found that granting the requested relief would be contrary to the principles against retroactive or retrospective ratemaking.

Deferral Account Methodology Previously Approved

The AUC considered that its approval of the deferral account methodology in its previous decisions approved both the allocation and the methodology on a final basis.

Specifically, the AUC found that

(a) a final decision on the deferral account methodology was made in Decision 2009-010; and

(b) final decisions approving the specific allocation methodology, cost and cost variances, and deferral account amounts has already been issued for the years 2010 through 2014, as set out in the list of decisions identified in paragraph 91 of the Decision.

The AUC held that the AESO's customers should be able to rely on the finality of the AUC's decisions with respect to these aspects of prior deferral account reconciliations.

Retroactive Ratemaking

The AUC found that the PS Group's request to change the allocation methodology to use Rate DTS connection charges net of Rate PSC credits would require a change to Rider C in the ISO tariff. The AUC held that the absence of express language in the ISO tariff that Rate PSC is subject to deferral account treatment in the approved tariff prevents the PS Group's requested relief from falling under the deferral account exception to the rule against retroactive/retrospective ratemaking.

The AUC held that, although AESO customers are aware that Rate DTS and Rate FTS are subject to deferral account adjustments, customers could not reasonably have known that the AESO's deferral account would be used to change anything other than a revenue or cost item. On this basis, the AUC concluded that approval of the deferral account methodology in its previous decisions approved both the allocation and the methodology on a final basis.

No New Information/Failure to Bring Concerns in Timely Manner

The AUC further supported its decision by finding that the relief requested was not brought forward in a timely manner. The AUC held that, even had it found the requested relief as falling under the deferral account exception to retroactive making, the PS Group's adjustment as far back as 2008 would be unreasonable.

The AUC found that there was no new or different information available to the PS Group in April or May, 2016 that would not have been available to PS Group members during the course of the proceeding that led to Decision 2009-010 where the deferral account allocation methodology was first used, or during the five deferral account reconciliation proceedings that followed.

The AUC found that relevant information was available within the deferral account reconciliation applications such that the concerns of the PS Group could have been identified well before 2016.

Direction to the AESO

The AUC directed the AESO to address whether changes to the deferral account allocation methodology and to Rider C are warranted given the concerns raised by the PS Group, as part of its next ISO tariff application.

Bulletin 2017-03: Consultation regarding the Alberta Utilities Commission's enforcement policy and practices
Bulletin – Enforcement Policy & Practices

On November 1, 2016, the AUC issued Bulletin 2016-20, inviting stakeholder feedback regarding the AUC's enforcement program.

In this Bulletin, the AUC provided its responses to comments received from ENMAX Corporation and the Utilities Consumer Advocate. The AUC stated that after reviewing those comments, it will not be making any changes to its enforcement policies at this time.

However, the AUC stated it will consider those comments where applicable, when carrying out its enforcement functions.

Those stakeholder comments and the AUC's responses can be found in the comment matrix attached to Bulletin 2017-03.

Bulletin 2017-04: Stakeholder comments sought for changes to AUC Rule 024: Rules Respecting Micro-Generation
Bulletin – Micro-Generation Rules

The AUC invited stakeholders written comments regarding proposed changes to AUC Rule 024: *Rules Respecting Micro-Generation*.

A draft of the proposed new *Rule 024* is posted on the AUC website.

NATIONAL ENERGY BOARD

Westcoast Energy Inc. Application for Review of Decision re Toll Treatment of the Tower Lake Section (GH-003-2015)
Review Application – Tolling Methodology – System Expansion/Extension

Background

In October 2016, the NEB issued its decision (the "Decision") regarding NOVA Gas Transmission Limited's ("NGTL") application for the Towerbirch Expansion Project (the "Project") located in northwest Alberta and northeast British Columbia ("BC").

In the Decision, the original NEB panel recommended approval of the Project, consisting of a mainline expansion and an extension known as the Tower Lake Section (the "TLS"). The original panel also approved, in a 2-1 split decision, NGTL's applied-for rolled-in tolling treatment on the TLS, subject to the condition that NGTL reapply for approval if the TLS used ships gas to alternate delivery markets in the future (including LNG export facilities).

Member Parrish dissented, stating that he would deny the applied-for tolling methodology on the TLS and require NGTL to re-apply for an alternative tolling methodology that respects both the user-pay principle and allows for fair competition to access supply and the NGTL System.

On November 10, 2016, Westcoast filed an application pursuant to subsection 21(1) of the *National Energy Board Act* (the "*NEB Act*") for a review of the TLS Tolling Decision ("Review Application"). Section 21(1) NEB Act states:

> 21 (1) … the Board may review, vary or rescind any decision or order made by it or rehear any application before deciding it.

Section 45(1)(a(i) of the *National Energy Board Rules of Practice and Procedure, 1995* (the "NEB Rules") provides that the NEB may dismiss an application for review if "the applicant has not … raised a doubt as to the correctness of the Board's decision or order."

The NEB review panel denied Westcoast's Review Application, holding that Westcoast failed to present grounds that raised a doubt as to the correctness of the original panel's decision.

Standard of Review

The review panel stated that at the first stage of the review, it must determine whether a doubt has been raised as to the correctness of the TLS Tolling Decision.

The panel referenced *Trans Mountain Pipe Line Co. v. Canada (NEB)*, where the Federal Court of Appeal held: "…[w]hether or not tolls are just and reasonable is clearly a question of opinion…".

The review panel found that while the standard of review is correctness, what is being reviewed for correctness is largely a matter of informed judgment and opinion. The NEB confirmed that there is a high threshold for reviews of its decisions, its decision to grant review is discretionary, and that "this discretion must be exercised sparingly and with caution."

User-pay Principle and Cross Subsidization

The review panel rejected submissions of Westcoast and its supporters that in the Tolling TLS Decision, the original panel's majority reasons failed to consider evidence that the revenue from the FT-R tolls would not fully cover the costs of both the TLS and the existing NGTL System. Rather, in the review panel's opinion, the original panel appropriately found that NGTL System shippers bear financial responsibility for some of the costs of the TLS.

The review panel also found that the original panel appropriately based its review of this issue, not on a narrow view, but in the context of the entire NGTL System. The review panel explained that in these circumstances, it is not an error for the Board to have found that:

- the user-pay principle does not require actual use, or
- by using the NGTL System, shippers use the TLS as well as other integrated laterals.

Having found no departure from the cost-causation or user-pay principle, the review panel concluded that the original panel did not err in finding that there was no cross-subsidization.

Economic Efficiency

The review panel noted that it is not required to consider the tolling principle of economic efficiency under the legislation. However, the review panel acknowledged that all members of the original panel did consider economic efficiency.

Further, the review panel noted that the original panel was not required to address each issue or sub-issue in its reasons, nor was it required to give economic efficiency any particular weight among its various considerations, regardless of the weight assigned by previous NEB panels.

The review panel concluded that Westcoast had not raised a doubt as to the correctness of the Decision on economic efficiency grounds.

Unjust Discrimination

Sections 62 and 63 of the *NEB Act* required that the same toll be charged for service "under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route".

The review panel found that such determinations of the original panel are questions of fact. Specifically, the review panel found that the original panel's findings that there was no unjust discrimination were findings of fact, based on the evidence before it.

The review panel concluded that that Westcoast had not raised a doubt as to the correctness of the TLS Tolling Decision on these grounds.

NEB Examination to Determine Whether to Undertake an Inquiry of the Tolling Methodologies, Tariff Provisions and Competition in Northeast BC
NEB Examination/Inquiry – Tolling Methodology – System Expansions/Extensions

On the same day the NEB issued its decision denying Westcoast's review application, the NEB also issued a letter to the attention of:

- Westcoast Energy Inc., carrying on business as Spectra Energy Transmission ("Westcoast");
- NOVA Gas Transmission Ltd. ("NGTL"); and
- Alliance Pipeline Ltd.

In the letter, the NEB noted that the competitive landscape in Northeast BC is comprised of pipeline systems owned by NGTL, Westcoast and Alliance. The NEB noted that these companies, each operating with distinct tolling methodologies and tariff provisions, compete for gas supply and transportation in a geographically concentrated area.

The NEB noted that facilities applications in Northeast BC have been contested on commercial grounds related to tolling methodologies to ensure fair competition and responsible development of the area. In addition, parties had previously requested that the NEB undertake a generic inquiry regarding tolling in Northeast BC, outside of the confines of any particular facilities application.

The NEB determined that it is appropriate to initiate an examination ("Examination") to determine whether:

(a) an inquiry of the tolling methodologies or tariff provisions of one or more of the Group 1 NEB-regulated natural gas pipeline companies operating in Northeast BC (the "Inquiry") is warranted; and

(b) what the scope of the Inquiry should include.

As a first step leading to any potential inquiry, the NEB requested that interested parties file with the NEB by April 21, 2017, comments on the following questions:

(a) What process should the Board establish for the Examination?

(b) What factors should the Board consider in its Examination?

(c) Is there a need for an Inquiry?

(d) What should the scope of the Inquiry include?

The NEB stated that after considering the comments received, further direction would be provided.

NEB Ruling No. 2 re TransCanada PipeLines Limited Energy East and Eastern Mainline Applications
Pipelines – Energy East – Eastern Mainline – Procedural Ruling

Background

In this decision, the NEB ruled that it will review the Energy East and Eastern Mainline Pipeline Applications (the "Applications") concurrently. This was the second ruling of the new panel considering the Applications in the recommenced hearing process following the recusal of the original panel in September 2016.

Energy East is a 4,500-kilometre pipeline proposed to carry 1.1 million barrels of crude oil per day from Alberta and Saskatchewan to refineries in Eastern Canada and a marine terminal in New Brunswick.

The applied-for Eastern Mainline Pipeline would consist of approximately 279 kilometres of new gas pipeline and related components, beginning near Markham, Ontario and finishing near Brouseville, Ontario. TCPL indicated in its application that this project was conditional upon the approval of the Energy East Pipeline Project.

The NEB found that the two project applications were closely interrelated and would be most efficiently assessed through a coordinated approach.

NEB Rulings

Ruling No. 2 consists of the following specific NEB rulings regarding its process for the consideration of the Applications:

- 2.1 The two applications will be heard together based on a common hearing record.

- 2.2 The NEB will consider both applications concurrently for the purpose of making its application completeness decision.

- 2.3 Each application will be subject to a full review pursuant to the requirements of the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* ("*CEAA 2012*").

- 2.4 The NEB will issue a separate List of Issues for each application.

- 2.5 The Projects will be scoped separately and each will have its own environmental assessment, as required under *CEAA 2012*.

- 2.6 Where appropriate, the Board will issue other documents or hold oral sessions specific to each application.

- 2.7 The Board will issue two separate reports at the end of the hearing process, each with its set of recommendations.

The NEB stated in a press release that information about next steps in the hearing process will be released in the coming weeks.