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DECISIONS

REGULATORY LAW CHAMBERS

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 COURT OF QUEEN'S BENCH

ENMAX Energy Corporation v. Balancing Pool (2017 ABQB 718)
Power Purchase Arrangement – Injunction Application – Injunction Granted

In this decision, the Alberta Court of Queen's Bench ("ABQB") considered an application by ENMAX Energy Corporation ("ENMAX") for (the "Application"):

(a) an interim injunction compelling the Balancing Pool to complete and communicate the results of its assessment and verification of ENMAX's Termination Notice (the "Termination Notice") in respect of the Power Purchase Arrangement ("PPA") for the Keephills Generation Facility (the "Keephills PPA");

(b) an interim injunction compelling the Balancing Pool to take offer and dispatch of Keephills Units 1 and 2 without further delay; and

(c) in the alternative, the determination of an issue of law, namely whether the Balancing Pool is required to fulfill its statutory obligations to complete and communicate the results of its assessment and verification of the Keephills Termination Notice and take offer and dispatch control of Keephills Units 1 and 2.

For the reasons summarized below, the ABQB:

(a) granted an interim injunction compelling the Balancing Pool to complete and communicate the results of its assessment and verification of the Termination Notice; and

(b) dismissed, as premature, ENMAX's application for an interim injunction compelling the Balancing Pool to take offer and dispatch control of Keephills Units 1 and 2.

Background: Keephills PPA and Termination under Change in Law Clause

Power Purchase Arrangements and Termination Clause

The ABQB explained:

- PPAs were developed to help facilitate the transition to a deregulated wholesale electricity generation market in Alberta, commencing in the mid-1990s.
- PPAs are similar in form to contracts but enacted through the *Power Purchase Arrangements Determination Regulation* and have statutory force by virtue of section 96(1) of the *Electric Utilities Act* ('*EUA*").
- PPAs allow owners of generating units to own and operate their facilities but auction the dispatch rights and beneficial ownership of the associated energy to the PPA buyers ("Buyers"). The PPAs grant to the Buyers the right to the capacity and the electricity generated by the generating units. The Buyers can then sell the electricity they have purchased directly to their own customers, or to the Power Pool.
- Article 4.3(j) of every PPA allows the Buyer to terminate a PPA in response to increased costs as a result of a change in law in certain circumstances.
- The Government of Alberta made certain amendments to the *Specified Gas Emitters Regulation*, effective January 1, 2016, which resulted in increased costs of producing coal-generated electricity. As a result, every PPA Buyer, including ENMAX, took steps to terminate their PPAs under Article 4.3(j).

The ABQB also noted that Article 4.3(j) of all PPAs was the subject of litigation between the Attorney General of Alberta ("Alberta AG") and various parties including ENMAX PPA Management Inc., the Balancing Pool, and other PPA Buyers in separate but related ABQB proceedings (the "AG Action"). In that dispute, the Alberta AG contended that Article 4.3(j) allows Buyers to terminate a PPA only where a change in law has rendered the PPA unprofitable for the Buyer. The respondents in that action, including ENMAX PPA Management Inc., argued that Article 4.3(j) allows Buyers to terminate a PPA where the change in law has rendered the PPA unprofitable or *more unprofitable* for the Buyer.

ENMAX's termination of the Keephills PPA

In this case, the ABQB explained:

- The Keephills Generation Facility is a coal-fired electrical generating station owned and operated by TransAlta Corporation and Capital Power.
- ENMAX purchased electricity produced from the Keephills Generation Facility under the Keephills PPA.
- On May 5, 2016, ENMAX provided the Termination Notice to the Balancing Pool that it was terminating the Keephills PPA effective that same day.
- On May 26, 2016, the Balancing Pool notified ENMAX that it had commenced its investigation and assessment pursuant to section 2(1) of the *Balancing Pool Regulation* ("*BPR*").

Termination under Section 2 of the Balancing Pool Regulation

The mechanism for initiating the termination of a PPA is set out in section 2(1) of the *BPR*, which provides that, on receipt of notice in respect of an extraordinary event, the Balancing Pool must conduct any investigation the Balancing Pool determines appropriate, and:

(a) agree that the extraordinary event occurred and that there is a need for a payment to be made to or by the Balancing Pool, or

(b) assess and verify the occurrence of the extraordinary event and the need for any payment to be made by or to a party under the provisions of the PPA and participate in any dispute resolution proceedings.

Once a PPA is terminated, it is deemed to have been sold to the Balancing Pool pursuant to section 96(3) of the *EUA*.

<u>ABQB Reasons for Granting Injunction Compelling Balancing Pool to Complete Assessment of Termination Notice</u>

ENMAX requested an interim injunction compelling the Balancing Pool to complete and communicate the result of its assessment and verification of the Termination Notice.

The parties agreed that the test for injunctive relief was the test set out by the Supreme Court of Canada ("SCC") in *RJR-MacDonald Inc. v. Canada (Attorney General)*, ([1994] 1 SCR 311 ("*RJR-MacDonald*").

Under the *RJR-MacDonald* test, the person applying for an injunction must establish the following three elements:

(a) there is a serious issue to be tried;

(b) the applicant will suffer irreparable harm if the injunction is denied; and

(c) the balance of convenience between the parties favours granting the injunction.

Considering "serious issue to be tried"

The ABQB found that the first injunction requested by ENMAX was properly characterized as a mandatory injunction (i.e. compelling the Balancing Pool to carry out a positive act). Therefore, ENMAX was required to demonstrate a strong *prima facie* case to meet the "serious issue" element of the *RJR-MacDonald* test.

The ABQB concluded that ENMAX had a strong *prima facie* case in respect of the Balancing Pool's breach of its obligation to complete its assessment of the Termination Notice. This conclusion was supported by the following findings:

(a) the language of *BPR* section 2(1)(g) is mandatory (i.e. the Balancing Pool must complete an assessment of the Termination Notice);

(b) by indefinitely deferring the assessment, the Balancing Pool was not determining the kind of investigation that is appropriate under *BPR* section 2(1)(g)(i);

(c) the Balancing Pool, for all practical purposes, was declining to proceed with the assessment, contrary to its mandate; and

(d) the Balancing Pool's refusal to complete an assessment of the Termination Notice, pending the outcome of the AG Action, was a breach of its obligation under *BPR* section 2(1)(g).

Considering "irreparable harm"

In *RJR-MacDonald*, the SCC described irreparable harm as follows:

> "Irreparable" refers to the nature of the harm suffered rather than its magnitude. It is harm which either cannot be quantified in monetary terms or which cannot be cured, usually because one party cannot collect damages from the other. Examples of the former include instances where one party will be put out of business by the court's decision; where one party will suffer permanent market loss or irrevocable damage to its business reputation; or where a permanent loss of natural resources will be the result when a challenged activity is not enjoined.

The ABQB found that the proper test in Alberta is whether the applicant has established that there is doubt as to the adequacy of damages.

Given the complex and varied set of factors that determine the cost and the price of electricity at any given time, the ABQB found there was real doubt as to whether the costs to ENMAX resulting from the Balancing Pool's failure to acknowledge the Termination Notice in a timely way could adequately be proved and compensated for in damages.

The ABQB explained that PPA Buyers, such as ENMAX, purchase, in advance, electrical capacity, and then sell that electricity to their customers. Owners are paid for the amount of electricity they produce. End users are charged for the amount of electricity they consume. The level of demand is constantly in flux.

The ABQB found that:

(a) when ENMAX purported to terminate the Keephills PPA, it could no longer accept electricity under that arrangement; and

(b) ENMAX purchased that power — hundreds' of millions of dollars' worth somewhere else, but the Keephills plant continued to generate electricity, which continued to be dispatched into the market by ENMAX.

The ABQB noted three possible outcomes following the Balancing Pool completing its assessment of the Termination Notice:

(a) the Balancing Pool concluded that ENMAX was not entitled to terminate the PPA, and that decision was upheld in the arbitration or litigation that would inevitably follow, ENMAX's power purchase to replace power under the Keephills PPA may ultimately be simply an unfortunate business decision, with no damages to claim;

(b) if the Balancing Pool concluded that ENMAX was not entitled to terminate the PPA, but that decision was not upheld in subsequent proceedings, there would doubtless be a complex damages assessment to determine the costs to ENMAX resulting from the Balancing Pool's failure to acknowledge the Termination Notice in a timely way; or

(c) the result of the Balancing Pool's assessment would be that ENMAX is entitled to terminate the Keephills PPA.

The ABQB found that under any of those scenarios, the question remained as to whether ENMAX would ultimately be required to take the Keephills power.

Considering "balance of convenience"

The ABQB rejected the Balancing Pool's argument that the balance of convenience weighed in favour of denying the injunction, based on there being incomplete information pending the outcome of the AG Action. The ABQB found that to wait until there was a resolution in the AG Action, which was effectively to wait indefinitely, would be an abrogation of the Balancing Pool's responsibility to conduct an assessment.

<u>ABQB Reasons for Denying Injunction Compelling Balancing Pool to Take Offer and Dispatch Control</u>

The ABQB went on to consider ENMAX's second injunction application, in which it requested an interim injunction compelling the Balancing Pool to take offer and dispatch of Keephills units 1 and 2 forthwith.

Considering "Serious Issue to be Tried"

The ABQB found that ENMAX sought to have the Balancing Pool carry out a positive act. An injunction of this nature was mandatory and therefore required ENMAX to demonstrate a strong *prima facie* case.

The ABQB found that it was difficult to understand the *prima facie* case of ENMAX that the Balancing Pool breached its legislative duties, based on the ABQB's findings that.

(a) the legislation (*EUA* section 96) did not require the Balancing Pool to assume offer and dispatch control unless and until the PPA was terminated and thereby deemed sold to the Balancing Pool;

(b) notwithstanding ENMAX taking steps to terminate the Keephills PPA, the PPA was not yet terminated pending the Balancing Pool's assessment of the Termination Notice; and

(c) therefore, there was no breach of any obligation on the part of the Balancing Pool.

Irreparable Harm

The ABQB noted that neither the Balancing Pool nor ENMAX provided evidence as to whether ENMAX was billing the Balancing Pool or being paid. The ABQB concluded that there was therefore no evidence of irreparable harm.

Balance of Convenience

The ABQB found that ENMAX failed in a consideration of whether the balance of convenience favours it because its application was premature. There was no ability for ENMAX to call for dispatch and offer control to be assumed by the Balancing Pool until the PPA was terminated, which termination had not yet been assessed or confirmed.

<u>Declaration on Issue of Law</u>

Given its disposition of the interim injunction applications by ENMAX, the ABQB determined that ENMAX's alternative application for a declaration as to an issue of law had been dealt with.

<u>Decision</u>

In summary, the ABQB:

(a) granted an injunction in favour of ENMAX, compelling the Balancing Pool complete and communicate the result of its assessment and verification of the Termination Notice issued on May 5, 2016 by ENMAX in respect of the Keephill's PPA without further delay; and

(b) dismissed the application by ENMAX for an interim injunction compelling the Balancing Pool to assume offer and dispatch control with respect to the Keephills PPA.

ALBERTA ENERGY REGULATOR

Declaration naming Gary Schellenberg and Lorne Hill under section 106 of the Oil and Gas Conservation Act
Declaration under Section 106 of the Oil and Gas Conservation Act

On October 30, 2017, the AER notified Gary Schellenberg and Lorne Hill of its intention to name them in a declaration pursuant to section 106 of the *Oil and Gas Conservation Act* ("*OGCA*"). The AER noted that it did not receive any response from Mr. Schellenberg or Mr. Hill on this matter.

The AER issued a declaration under section 106(1) of the *OGCA* naming Gary Schellenberg and Lorne Hill as persons in direct or indirect control of Golden Coast Energy Corp. ("Golden Coast"), a company that contravened or failed to comply with an AER order and has a debt to the AER.

Declaration under Section 106 of the *OGCA*

The AER explained that *OGCA* Section 106 applies where the AER considers it in the public interest to make a declaration naming one or more directors, officers, agents, or other persons who, in the AER's opinion, were directly or indirectly in control of a licensee, approval holder, or working interest participant that has:

(a) contravened or failed to comply with an order of the AER; or

(b) an outstanding debt to the AER, or to the AER to the account of the orphan fund, in respect of suspension, abandonment, or reclamation costs.

The AER noted its previous holdings in *OGCA* section 106 decisions that:

(a) the purpose of a section 106 declaration is to prevent a licensee or person in control from continuing to breach requirements or incurring new breaches or debts, thereby safeguarding the public interest; and

(b) continued confidence in the regulatory system is best assured when licensees comply with AER requirements.

Background

Golden Coast held eight operational well licenses, five operational pipeline licenses, and three abandoned well licenses.

In March 2016, Golden Coast informed the AER that the company was ceasing operations, that the company's last two directors, Mr. Schellenberg and Mr. Hill, had resigned, and that all of the company's remaining assets would be forfeited to the AER. The AER issued Golden Coast a closure and abandonment order.

AER inspectors later discovered that a sour gas well licensed to Golden Coast was leaking.

The AER determined that Golden Coast failed to comply with the closure and abandonment order and failed to initiate immediate action in response to calls the AER inspectors made to the company's emergency phone number regarding the leaking sour gas well.

The AER also found that Golden Coast had not paid its debt to the AER arising from (i) the AER's emergency response to the leaking sour gas well; (ii) Golden Coast's 2016 Orphan Fee Levy; (iii) Golden Coast's Administrative Fees Levy; and (iv) associated penalties for nonpayment.

The AER found that:

(a) these non-compliances and nonpayment of debts were the result of Golden Coast's decision to "walk away" from its AER licensed properties;

(b) simply notifying the AER of a licensee's intention to "walk away" from its licensed properties does not absolve that licensee of its ongoing obligations under AER legislation;

(c) one of Golden Coast's licensed properties subsequently posed a potential public safety and environmental risk, a fact highlighted by Golden Coast's failure to ensure that calls to the company's emergency telephone number regarding the leaking sour gas well initiated an immediate response. Golden Coast's decision to "walk away" from its licensed properties and the company's ongoing failure to comply demonstrate a blatant disregard for AER requirements; and

(d) as directors of Golden Coast at the time of the company's noncompliances and nonpayment of debts, the named individuals were and are persons in control of Golden Coast.

The AER found that Golden Coast's actions had undermined the regulatory system and posed an unacceptable risk to public safety and the environment. The AER concluded that issuance of a declaration was necessary to deter future noncompliance and uphold the credibility of the regulatory system and AER enforcement processes. It is not in the public interest to allow licensees like Golden Coast to simply "walk away" from their AER licensed properties and ongoing regulatory responsibilities.

Request for Regulatory Appeal by Ken Cowles - Jupiter Resources Inc. Well Licences
Regulatory Appeal Request – Request Denied

In this decision, the AER considered Mr. Cowles' requests under section 38 of the *Responsible Energy Development Act* ("*REDA"*) for regulatory appeals of the AER's decisions to approve certain well licences (the "Licences") issued to Jupiter Resources Inc. ("Jupiter"). The Licences were issued in December 2015, allowing Jupiter to drill and produce fourteen natural gas wells.

For the reasons summarized below, the AER determined that: (1) Mr. Cowles did not file a statement of concern in relation to the applications for which the Licences were issued; and (2) in any case, the record does not indicate that Mr. Cowles was directly and adversely affected by the AER's decisions to issue the Licences.

The AER therefore dismissed the requests for regulatory appeals.

AER Reasons

Mr. Cowles not filing a Statement of Concern

Mr. Cowles submitted that he was either not aware that Jupiter had filed the Applications, or that he needed to file a statement of concern.

The AER found that:

(a) Jupiter notified Mr. Cowles of its intention to file the Applications and waited at least 14 days before filing the Applications as routine; and

(b) Jupiter had reason to believe Mr. Cowles' unresolved concerns only related to compensation, and that he preferred to discuss that issue directly with Jupiter rather than by filing a statement of concern, as per the AER process.

Mr. Cowles was not directly and adversely affected by decision to issue Licences

The AER explained that for Mr. Cowles to be granted a regulatory appeal, he must demonstrate that the particular Jupiter wells subject to the Licences were the activities responsible for the impacts that he is concerned about, namely: damage to his trapping trails and lines, property theft and vandalism, hazardous use of roadways, and the disappearance of fur-bearing wildlife.

The AER found that Mr. Coals was not directly and adversely affected by the AER's decisions, based on its findings that:

(a) Mr. Cowles' concerns with the Applications were stated in a general way, without reference to a particular location that was some ascertainable distance from his trapping activities or assets; and

(b) the requests failed to provide information to demonstrate a degree of location or connection between one or more of the wells and impacts on Mr. Cowles or his trapping activities.

The AER found that there was insufficient reliable information to show that a reasonable potential or probability existed that the impacts alleged by Mr. Cowles would occur.

As a result, the AER found that it could not conclude that any of Jupiter's wells would directly and adversely affect Mr. Cowles.

Decision

For this reason, and the fact that Mr. Cowles did not file statements of concern in relation to the applications, the AER decided not to grant the requests for regulatory appeals.

ALBERTA UTILITIES COMMISSION

Enel Alberta Wind Inc. – Complaint Pursuant to Section 26 of the Electric Utilities Act Regarding Conduct of the Alberta Electric System Operator (Decision 22367-D01-2017)

Section 26 of the Electric Utilities Act – Complaint Application Regarding AESO Conduct – Application Dismissed

On January 25, 2017, Enel Alberta Wind Inc. ("Enel"), the owner of the Castle Rock Ridge ("CRR") Wind Farm (the "CRR Wind Farm"), filed a complaint with the AUC regarding the conduct of the Alberta Electric System Operator ("AESO") (the "Complaint Application"), pursuant to Section 26 of the *Electric Utilities Act* ("*EUA*").

For the reasons summarized below, the AUC dismissed the Complaint Application.

Complaint Application

In the Complaint Application, Enel asserted that:

(a) to satisfy the requirements of the South Alberta Transmission Reinforcement plan ("SATR"), the AESO made a number of major changes to the requirements for the interconnection of the CRR Wind Farm to the Alberta Interconnected Electric System ("AIES");

(b) as a result of the changes made by the AESO, Enel was required to pay for facilities that were in excess of what was reasonably required to provide system access to the CRR Wind Farm, in excess of the minimum requirements to serve the CRR Wind Farm's need, and in excess of what was required by good electric industry practice;

(c) Enel was charged for radial transmission facilities that, within five years of commercial operation, were planned to become looped as part of the SATR regional transmission system project;

(d) the AESO's conduct in making these changes contravened section 47 of the *Transmission Regulation*, Section 8 of the 2011 Independent System Operator ("ISO") Tariff (the "ISO Tariff"): *Construction Contribution for Connection Projects*, and Section 9.3(c)(iii) of the 2006 ISO Tariff; and

(e) the AESO's conduct in interpreting and applying the ISO Tariff in determining the customer contribution to be paid by Enel for the CRR interconnection, amounted to unfair, arbitrary or discriminatory treatment of Enel.

Background

In September 2009, the AUC issued Decision 2009-126 approving the AESO's SATR Needs Identification Document ("NID") (the "SATR NID"). The SATR NID did not include the facilities specifically required to connect individual wind farms (including the CRR Wind Farm) in the Pincher Creek area.

In January 2009 the AUC approved the transfer of the CRR power plant approval from the previous developer (Wind Power Inc.) to Enel (the "Power Plant Approval").

In June 2010, the AESO filed the Fidler NID application (Proceeding 690) (the "Fidler NID"), which proposed the Fidler transmission development to facilitate the orderly connection of future wind farms in the Pincher Creek area. In this transmission development proposal, a 240 kV double-circuit transmission line was proposed from the Goose Lake 103S Substation to connect the CRR Wind Farm. The 240 kV transmission line was not proposed to go further west from the CRR Wind Farm to Crowsnest or Chapel Rock.

In August 2010, the AESO filed a NID application for the CRR Wind Farm interconnection to the AIES. This connection plan was predicated on the approval of the Fidler substation application, which was considered in Proceeding 690 at that time. AltaLink filed the corresponding facility applications with the AUC on October 15, 2010, seeking approval to construct and operate Castle Rock Ridge 205S Switching Station and associated 240 kV double-circuit transmission line 1071L/1072L from the 205S to Point A.

Enel completed construction of the CRR Wind Farm in March 2011. However, Proceeding 690 had not concluded and, as a result, the necessary transmission facilities were not ready to connect the CRR Wind Farm by its target in-service date of September 2011.

Amended CRR Wind Farm NID and Facility Applications

In response to the delay associated with approval of the Fidler NID and Enel's request that the AESO find a solution to connect the CRR Wind Farm as close as possible to its targeted in-service date, the AESO identified two options for Enel's consideration:

(a) Option 1A proposed to connect the 205S Switching Station to Goose Lake 103S Substation by means of a new nine-kilometer segment of 240 kV double-circuit transmission line (1071L/1072) from the proposed Castle Rock Ridge 205S Switching Station to the existing Goose Lake 103S Substation; and

(b) Option 2A, the less expensive option, for the construction of a system switching station at Point A and a single circuit 240 kV transmission line from the switching station at Point A to the CRR Wind Farm. A disadvantage identified with option 2A was that costs already incurred on the project, such as consultation, initial engineering and design and material procurement would be included in the single circuit option costs. Further, AltaLink advised that the related re-work in respect of the single circuit option, would further delay the already delayed in-service date.

Reserving its rights to challenge the cost estimates and classification with the AESO, Enel identified option 1A as its preferred option. During preparation of the amendment application, the AESO advised Enel that the $25.2 million cost of the proposed development identified in the CRR Wind Farm NID would be participant-related.

In Decision 2011-439, the AUC approved the combined CRR Wind Farm NID and facility applications as amended and issued the necessary permits and licences.

AESO Dispute Resolution Process

In June 2016, Enel submitted a written dispute to the AESO in accordance with the ISO Rules. The AESO issued its decision on dispute resolution in August 2016 (the "AESO Dispute Resolution Decision").

Legislative Scheme

The AUC explained that its role *vis-à-vis* the AESO includes ruling on matters brought before it by the AESO and also ruling on complaints brought by others relating to the conduct of the AESO. The AUC noted that the AESO's exercise of its authority is not unlimited and is subject to a number of checks, including the following:

(a) First, the AESO has a statutory duty to act fairly and responsibly;

(b) Second, the ISO Tariff must be approved by the AUC;

(c) Third, the AUC must approve needs identification documents prepared by the AESO and adjudicate if the need for new transmission infrastructure is contested by an interested party; and

(d) Fourth, a person who has a concern about the conduct of the AESO may make a complaint about that conduct to the Commission, pursuant to Section 26 of the *EUA*.

EUA Section 26 - Complaints about the ISO

Section 26 of the *EUA* authorizes the AUC to rule on complaints by any person about the conduct of the AESO:

> Complaints about ISO
>
> 26(1) Any person may make a written complaint to the Commission about the conduct of the Independent System Operator.

Subsection 26(2) prescribes circumstances in which a complaint must be dismissed:

> (2) The Commission must dismiss the complaint, giving reasons for the dismissal, if the Commission is satisfied that
>
> (a) the substance of the complaint has been or should be referred to the Market Surveillance Administrator for investigation,
>
> (b) the complaint relates to a matter the substance of which is before or has been dealt with by the Commission or any other body, or
>
> (c) the complaint is frivolous, vexatious or trivial or otherwise does not warrant an investigation or a hearing.

Subsection 26(3) provides the AUC discretion and remedial powers when considering a complaint:

> (3) The Commission may, in considering a complaint, do one or more of the following:
>
> (a) dismiss all or part of the complaint;
>
> (b) direct the Independent System Operator to change its conduct in relation to a matter that is the subject of the complaint;
>
> (c) direct the Independent System Operator to refrain from the conduct that is the subject of the complaint.

in Decision 2010-104, the AUC previously set out examples of the types of complaints *EUA* section 26 was intended to address, including but not limited to, the following:

- complaints about the AESO's compliance with Commission rules;
- complaints about the AESO's consultation with interested parties; and
- complaints about the AESO relating to procedural rights in the AESO processes that do not relate to the making of rules or setting of fees.

The AUC explained that the nature of prior complaints had generally been concerned with AESO conduct that had an alleged adverse effect on a person's position. The AUC found that the policy reason behind *EUA* section 26 were to provide market participants with an opportunity for redress in circumstances where the AESO's decisions had a negative effect, where the AESO's conduct was at issue and where there was no clear alternative mechanism available to address the subject matter of the complaint.

AESO's Duties

To provide further context for its determination of the issues raised in the Complaint Application, the AUC provided an overview of the relevant statutory framework:

- Section 17 of the *EUA* provides that the AESO's duties include, amongst other things:
  - (i) to provide system access service on the transmission system and to prepare an ISO tariff [*EUA* s 17(g)];
  - (ii) to direct the safe, reliable and economic operation of the interconnected electric system [*EUA* s 17(h)];
  - (iii) to assess the current and future needs of market participants and plan the capability of the transmission system to meet those needs [*EUA* s 17(i)]; and
  - (iv) to make arrangements for the expansion of and enhancement to the transmission system [*EUA* s 17(j)].
- Section 20(1) of the *EUA* provides that the AESO may make rules respecting, *inter alia*, the AESO's practice and procedures, the exchange of electric energy through the power pool, the operation of the AIES, and planning the transmission system, including criteria and standards for the reliability and adequacy of the transmission system.
- Section 33 of the *EUA* states that the AESO "must forecast the needs of Alberta and develop plans for the transmission system to provide efficient, reliable and non-discriminatory system access service and the timely implementation of required transmission system expansions and enhancements."
- Sections 8 and 10 of the *Transmission Regulation* require that the AESO forecast the needs of Alberta and plan the transmission system to meet those needs.
- Section 15 of the *Transmission Regulation* outlines the matters the AESO must take into account when making rules and exercising its duties.
- Section 90 of the *EUA* provides immunity for the AESO from liability for "acts" that include acts and omissions carried out in the exercise of its mandate, unless the acts constitute wilful misconduct, negligence or breach of contract or the acts were not carried out in good faith.

The AUC found that, when read as a whole, the statutory scheme makes clear the fundamental importance of planning the transmission system so that the structure of the Alberta Electric industry is not distorted by unfair advantages given to any participant.

<u>Jurisdiction to Consider Complaint</u>

The AUC found that it had jurisdiction under *EUA* Section 26 to consider the Complaint. Specifically, the AUC found that its jurisdiction under *EUA* section 26 allowed for consideration of the AESO's conduct leading up to the AESO Dispute Resolution Decision and the AESO's findings in that decision.

Having found that it had jurisdiction to consider the complaint, the AUC concluded that it therefore had the jurisdiction under sections 26(3)(b) and (c) of the *EUA* to direct the AESO to change its conduct or to refrain from the conduct that was the subject of the complaint.

<u>Preliminary Issue under Section 26(2) of the *EUA*</u>

Must the AUC Dismiss the Complaint Application under EUA Section 26(2)(b)?

Section 26(2) of the *EUA* directs the AUC to address, as a preliminary issue, whether any of the criteria established by that subsection are satisfied such that the complaint must be dismissed.

The AUC found that only *EUA* subsection 26(2)(b) had possible application to the Complaint Application, that is, whether the complaint related to a matter the substance of which was before or had been dealt with by the AUC or any other body.

The AUC explained that it conducts a two-step analysis when considering *EUA* section 26(2)(b):

(a) at the first step, the AUC considers what the issue is, and

(b) at the second step, the AUC considers whether the issue had previously been determined or if the issue was being dealt with in another proceeding.

In this case, the AUC found that:

(a) the substance of the complaint concerned the conduct of the AESO in its interpretation and application of the ISO Tariff provisions and whether the AESO's conduct was inconsistent with the legislation, the ISO Tariff or otherwise amounts to improper, unfair or discriminatory treatment of Enel; and

(b) the AUC had not previously dealt with issues concerning the conduct of the AESO in its interpretation and application of the ISO Tariff provisions and whether that conduct amounted to improper, unfair or discriminatory treatment of Enel.

The AUC concluded that it could proceed to deal with the complaint insofar as it related to allegations with respect to the conduct of the AESO because none of the grounds listed in *EUA* section 26(2) were met. Accordingly, the AUC did not dismiss the complaint pursuant to that provision.

Duress

The AUC noted Enel's arguments that:

(a) Enel did not raise the issue of cost classification in the CRR Wind Farm NID application because, by that time, it was under duress, with the CRR Wind Farm having been constructed, but not yet connected to the AIES, due to the AESO's repeated changes in plans; and

(b) Enel had an obligation to mitigate its damages and obtain the fastest approval possible, all the while maintaining its reservation of right to contest the AESO's construction contribution determination.

Although Enel did not address the applicable legal test for economic duress, given Enel's assertion that it was under duress, the AUC set out the test for economic duress in a commercial setting. Establishing economic duress requires establishing the following elements:

(a) an illegitimate form of pressure;

(b) which was sufficient to overcome the will of the protesting party, such that it vitiated any consent or agreement; and

(c) which caused the entering into of the challenged transaction.

In other words, economic duress requires that there be illegitimate pressure, which only leaves the threatened party with no practical alternative but to comply with the demand.

The AUC noted its finding in Decision 3473-D02-2015, that "a market participant seeking a new connection to the transmission system has no inherent guarantee that it will receive system access service by a specified target in-service date."

Based on the above, the AUC found that:

(a) Enel's desire to connect the CRR Wind Farm to the AIES as quickly as possible and to agree with proposals made by the AESO to facilitate that desire did not alone constitute economic duress; and

(b) Enel failed to satisfy its evidentiary burden by providing any evidence of illegitimate pressure by the AESO.

Section 47 of the Transmission Regulation

Section 47 of the *Transmission Regulation* provides that in its consideration of an ISO Tariff application, the AUC must ensure:

(a) the just and reasonable costs of the transmission system are wholly charged to Distribution Faciltiy Owners ("DFOs") [s. 47(a)], and

(b) owners of generating units are charged local interconnection costs to connect to the transmission system and are charged a financial contribution toward transmission system upgrades and for location-based cost of losses [[s. 47(a)].

Enel argued that the majority of the facilities required for the CRR Wind Farm interconnection were system-related.

The AUC rejected these arguments, finding that Enel's construction contribution, as determined by the AESO, was consistent with the requirements of section 47 of the *Transmission Regulation*. In this regard, the AUC found that:

(a) there was nothing in the plain and ordinary meaning of the *Transmission Regulation* provisions that required that the costs of a project that the AESO has at some time referred to as a system project, be a cost recovered under subsection 47(a), to the exclusion of whole or partial cost recovery as a local interconnection cost recovered from the power plant owner under subsection 47(b); and

(b) therefore, the AUC was not persuaded that the AESO had charged costs to Enel in a way that violates the categorization principles for cost recovery outlined in Section 47 of the *Transmission Regulation*.

The AUC further found that the exercise of classifying costs as either participant-related or system-related was an approach that required the AESO to make classifications based on "shades of grey." When determining the cost allocation of a connecting market participant, the initial presumption is that costs should be classified as participant-related, unless clearly demonstrated otherwise.

Section 8 of the 2011 ISO Tariff Section 8

Subsections 2 of Section 8 of the ISO Tariff

Subsection 2 of section 8 of the 2011 ISO Tariff states:

2 The costs of a connection project for a market participant will be those costs reasonably associated with facilities that:

…

(b) are required to:

(i) provide system access service to a new … point of supply; … and

(c) are reasonably required to meet the market participant's:

(i) demand and supply forecast; and

(ii) reliability and operating requirements.

The AUC found that Enel failed to establish that the facilities required for the CRR Wind Farm interconnection were in excess of what was required, or that requiring Enel to pay for the cost of the contested facilities would yield a discriminatory, arbitrary, or unjust result.

In coming to this conclusion, the AUC explained that it relied on the principle of cost causation to determine if the AESO cost contribution decision was discriminatory or unjust. The AUC noted that at present, the CRR Wind Farm was the only project using the contested facilities and these facilities were constructed after the AESO received an interconnection request from Enel.

The AUC found that, in this case, the AESO followed an established classification framework that started with the assumption that the CRR Wind Farm interconnection costs were participant-related, which was consistent with the fact that the CRR Wind Farm interconnection facilities would not have been built but for the construction of the CRR Wind Farm.

Subsection 3(3)(b) of the ISO Tariff

Subsection 3(3)(b) identifies when the costs associated with radial transmission facilities will qualify as system-related costs. It states:

(3) System-related costs will be those costs related to a connection project including non contiguous components of the project and any costs associated with:

…

(b) radial transmission facilities which, within five (5) years of commercial operation, are planned to become looped as part of a critical transmission development or regional transmission system project:

(i) in the ISO's most recent long-term transmission system plan;

(ii) in a needs identification document filed with the Commission; or

(iii) as the ISO reasonably expects will be required in the future;

…

The AUC found that for subsection 3(3)(b) of Section 8 of the ISO Tariff to apply, as it existed in 2011, the evidence must establish that a plan to loop the CRR Wind Farm interconnection within five years of its commercial operation existed at the date the AUC issuing the permits and licences for those facilities.

The AUC found that Enel failed to provide such evidence. Therefore, the AUC concluded that Enel's construction contribution was not determined contrary to subsection 3(3)(b) of Section 8 of the ISO Tariff.

Decision

For the reasons summarized above, the Commission dismissed Enel's complaint against the AESO under Section 26 of the *EUA*.

Milner Power Inc. & ATCO Power Ltd. – Complaints Regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology (Decision 790-D06-2017)

Line Loss Rule – Module C

In this decision, the AUC approved a methodology for the calculation of final loss factors for the period between January 1, 2006 and December 31, 2016 (the "Historical Period"). The AUC also determined to whom revised invoices for line loss charges or credits for the historical period were to be issued.

Line Losses and Calculating Loss Factors

With respect to line losses, the AUC explained:

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

- In Alberta, the owner of the generating unit that produced the electricity, or the owner of the output of that generating unit through a Power Purchase Arrangement ("PPA"), pays the cost of this lost energy.

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

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

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

The Unlawful Line Loss Rule and AUC Proceeding 790

Original Milner Line Loss Rule Complaint

The genesis of this proceeding dates to 2005 when the AESO proposed a new methodology for calculating line losses (the "Line Loss Rule").

Milner filed a complaint about the Line Loss Rule on the basis that it did not comply with certain sections of the Transmission Regulation. The Alberta Energy and Utilities Board ("EUB"), the AUC's predecessor, dismissed Milner's complaint, but that decision was successfully appealed to the Alberta Court of Appeal ("ABCA"). The ABCA directed the Commission to reconsider whether the Line Loss Rule contravened section 19 (now section 31) of the *Transmission Regulation*, as alleged by Milner.

Proceeding 790: Phase 1

The Commission set up a two-phase process to re-hear Milner's complaint: Phase 1 to consider if the Line Loss Rule contravened the *Transmission Regulation*, and Phase 2 (if necessary) to determine the remedy if a contravention was found. In the Phase 1 decision (790-D02-2015), a majority of the AUC panel found that the Line Loss Rule contravened section 19 of the *Transmission Regulation* and upheld Milner's initial complaint as valid.

Proceeding 790 – Phase 2: Module A and Module B

The AUC considered Phase 2 of Proceeding 790 in three modules. In Module A (Decision 790-D02-2015), the AUC considered whether it could order a remedy to address unlawful payments made pursuant to the Line Loss Rule and concluded that it had the jurisdiction to make such an order. The AUC also determined that the unlawful rates were interim.

In Module B, the Commission heard proposals for a new line loss methodology to replace the Line Loss Rule, and in Decision 790-D03-2015 approved a methodology for determining loss factors on a go forward basis starting on January 1, 2017, known as the Module B methodology.

Module C – Subject of this Decision

In this decision regarding the final module (Module C) of Proceeding 790, the AUC had to determine what methodology should be used for the Historical Period and to whom the AESO must re-issue invoices (for charges or credits) for that period.

The AUC set out, with respect to the Historical Period, the following questions it was tasked with determining in this decision:

(a) Which methodology to apply to the historical period;

(b) Which parties should, at first instance, receive invoices for the final line loss rates; and

(c) What should the process be for collection and payment of the amounts resulting from those final rates.

Question 1: Methodology to Apply to the Historical Period

Modified Module B Methodology

In Decision 790-D03-2015 (regarding the replacement Line Loss Rule), the Commission directed changes to the Line Loss Rule (ISO rules Section 501.10) on a prospective basis. The changes included:

(a) replacing the previous rule with an incremental loss factor ("ILF") methodology for calculating raw loss factors;

(b) specifying that the location of a generation facility will be the location of each metering point identifier (MPID) for a generating unit or group of generating units;

(c) allowing generators that own or control generating facilities to aggregate or disaggregate their generating facilities at the same location;

(d) keeping load constant when a generation facility is notionally removed from the system and scaling up other specific generation facilities to rebalance the system; and

(e) instead of using 12 base cases, the 8,760 energy market merit orders would be used during the process of calculating forecast loss factors.

The AUC further directed in Decision 790-D04-2016 (regarding the compliance filing directed in Decision 790-D03-2016) that any methodology to be used for the Historical Period must exclude aggregation and use actual data rather than forecast data when calculating loss factors. The modified Module B methodology (the "Modified Module B Methodology") gave effect to this direction.

Which Methodology to Apply to the Historical Period

The AUC issued a summary in January 2017 of the views expressed by attendees at the December 20, 2016 round table meeting regarding potential methodologies. The AUC confirmed that only the following three methodologies that were discussed at the round table meeting would be considered further:

(a) the Milner methodology;

(b) the old AESO methodology; and

(c) the Module B Methodology.

The AUC noted that the AESO stated that it did not directly support or oppose any of the three methodologies. It added, however, that it could implement any of these methodologies subject to certain qualifications.

The AUC considered and did not accept the AESO's proposed methodology on a forward-looking basis in Decision 790-D03-2015 (the "Old AESO Methodology"). It stated in that decision that "scaling down load to rebalance the system introduces a conceptual problem in terms of what is being measured in that it does not reflect what actually occurs on the system when a generating facility is, in fact, removed." The AUC further stated that while scaling down load does not in itself violate the *Transmission Regulation*, because the curtailment of load is hypothetical, the modelling results would be improved by better representing actual system conditions.

Legislative Requirements for Line Loss Rule

To be compliant, a line loss methodology must be consistent with the relevant provisions of the *EUA* and satisfy the requirements set out in section 31 (formerly Section 19) of the *Transmission Regulation*.

The following provisions of the *EUA* apply:

- Section 17(e) sets out the AESO's duty to manage and recover line losses;

- Section 30(4) of that *EUA* provides that the AESO may recover the costs of line losses from market participants by including those costs in its tariff or by establishing and charging fees for those costs;

- Section 121(2) of the *EUA* requires the Commission to ensure that the ISO tariff is consistent with the statutory scheme, just and reasonable and not unduly preferential, and is not arbitrary nor unjustly discriminatory; and

- A further underlying requirement arising from Section 5 of the *EUA* is that the approved ISO tariff must be consistent with the fair, efficient and openly competitive operation of the market.

Section 31 of the *Transmission Regulation* provides express direction regarding the criteria a line loss rule must satisfy, including that:

(a) the rule reasonably recovers the cost of transmission line losses;

(b) the rule is determined for each location on the transmission system as if no abnormal operating conditions exist; and

(c) the rule is representative of the impact on average system losses by each respective generating unit or group of generating units relative to load.

Determining the Preferred Methodology

The AUC determined that all three methodologies complied or may be capable of complying with the statutory scheme. Therefore, the AUC had to determine which methodology it should direct the AESO to implement for the Historical Period. The AUC found that three criteria were relevant to making this determination, namely:

(a) consistency;

(b) expediency (i.e., timeliness); and

(c) verifiability (i.e., replicability).

The AUC explained that, in this context, consistency meant the degree to which each methodology is able to reasonably represent (or emulate) what would happen on the AIES when a generating unit unexpectedly comes off line. Expediency related to the time necessary to successfully implement each methodology. Regarding the need for verifiability, market participants must be able to reasonably verify (i.e., replicate) the AESO's loss factor calculations.

AUC directs AESO to calculate loss factors for the Historical Period using the Modified Module B Methodology

The AUC directed the AESO to calculate loss factors for the historical period using the Modified Module B Methodology.

Of the three major criteria considered and relied upon, the AUC stated that most important proved to be the first criterion: consistency. The AUC found that:

(a) compared to the other two methodologies, the Modified Module B Methodology best produces loss factors that reasonably represent (or emulate) what would happen on the AIES when a generating unit unexpectedly comes off line;

(b) with respect to the second criterion, expediency, there was no material or substantive difference in the estimated implementation time for each of the three methodologies; and

(c) With respect to the third criterion (verifiability or replicability), that criterion provided an insufficient basis to distinguish between the merits of the three methodologies.

With respect to the consistency criterion, the AUC found that whenever a generating unit is notionally removed from the system, the Modified Module B Methodology:

(a) holds load constant and rebalances the system by re-dispatching generation using the actual merit order for each hour in the Historical Period; and

(b) measures the resultant change in losses to determine a loss factor for each location that is representative of the impact of the generating unit on average system losses relative to load.

Hence, the Modified Module B Methodology was the preferred methodology for producing loss factors for the Historical Period, because it was best able to reasonably represent (or emulate) what would actually happen on the AIES. This is important because the purpose of an incremental load factor line loss factor methodology is to calculate system-wide line losses with and without the presence of each generating unit on the system and, thus, the contribution of each generating unit to average system losses.

Accordingly, the AUC found that the Modified Module B methodology should be adopted by the AESO for the Historical Period in place of the marginal loss factor ("MLF") methodology underpinning the unlawful Line Loss Rule.

<u>Question 2: Who should receive revised invoices, current or original STS contract holders?</u>

Invoices must be issued to the STS contract holder at the time when the losses occurred

The AUC noted:

- In Decision 2012-104, the AUC found that the previous unlawful Line Loss Rule did not comply with the *Transmission Regulation* because it employed a methodology that disadvantaged loss savers and did not properly charge loss creators.

- As also found in Decision 2012-104, in rate design, the principle of cost-causation requires that there be no undue discrimination between ratepayers in the same class. Those who cause high costs should pay for the high costs and those whose costs are lower should pay less. Translated into the line loss rule, this would mean that, at the very least, loss causers should pay while loss savers should receive a credit. When those who lower line losses are actually charged while those causing losses are charged much less than their contribution, this not only is unduly discriminatory, but unjust.

With respect to who should receive the invoices, the AUC found that:

(a) but for the unlawful Line Loss Rule, the predecessor STS holders associated with historical line losses would have been responsible for the costs of those line losses;

(b) it would be contrary to the principle of cost causation and unjust and unreasonable, to allow predecessor STS contract holders to avoid responsibility for the losses they caused by not invoicing them for lawful final rates; and

(c) requiring that current STS contract holders be initially invoiced in these circumstances could be perceived as creating an incentive for undesirable opportunistic behavior.

The AUC stated that the re-distribution of historical line losses cannot be permitted to become a high-stakes game of "hot potato" in which the party holding the STS Contract when the music stops is liable to the AESO for eleven years of line loss charges.

The AUC clarified it was only determining which market participants the AESO must invoice, and that the ultimate responsibility for payment may rest with others pursuant to separate commercial agreements.

The AUC concluded that it was just and reasonable to issue final invoices to the same party that received the original (currently interim) invoices for line losses during the historical period.

Method and Timing of Collection and Reimbursement

The AUC agreed with the AESO that the most straightforward and efficient approach for the collection and reimbursement of funds for the Historical Period would be by way of retroactive adjustments to charges assessed under the ISO tariff. The AUC found that settlement under Module C would involve the AESO recalculating the bills for the historical period using the Modified Module B Methodology and issuing new statements of account.

Compliance Filing

The AUC determined that a new rule was not required to implement the necessary rate adjustments for the Historical Period. Rather, finalizing the previously interim line loss charges required direction from the AUC, and not a new rule to take effect.

The AUC found that a reasonable and efficient approach is for the AESO to submit a compliance filing for approval which documents the methodology and procedures that will be implemented to produce final line loss charges for the historical period, pursuant to the directions in this decision.

Order

Based on the above, the AUC ordered as follows:

(a) the AESO shall produce final loss factors for the Historical Period (from January 1, 2006 to December 31, 2016) using the Modified Module B Methodology.

(b) following such consultation with market participants as the AESO considers necessary in the public interest, the AESO shall submit a compliance filing for approval that specifies and describes how it will implement the Modified Module B methodology and related procedures.

(c) the AESO shall issue final invoices to the same parties that received the original (currently interim) invoices for line losses during the historical period.

(d) the AESO shall implement the single settlement approach for the historical period with simultaneous collection and reimbursement pursuant to the ISO tariff. [The singe settlement approach means a single, net settlement approach with one net charge collected or reimbursed to market participants only after all loss factors have been calculated for the historical period.]

(e) the AESO shall assign the necessary resources to implement the accelerated single settlement approach and recover the incremental cost through the energy market trading fee.

(f) the AESO shall provide updated statements of account for the final line loss charges to market participants setting out the recalculated line losses charges for the historical period on a year by year basis as they become available, before a final true-up takes place.

(g) the AESO shall charge/award interest, equal to the Bank of Canada rate plus one and one half per cent; the AESO shall set out the interest attributed to the monthly amounts for each market participant as it calculates and makes available the updated statements of account for the final line loss charges.

(h) the AESO shall develop the structure, terms and eligibility criteria for its proposed payment plan and file it with the compliance filing to this decision.

(i) the AESO shall recover through the energy market trading fee any incremental administration costs and any interest costs incurred by the AESO associated with credit facilities specific to the settlement process.

(j) the AESO shall collect any payment default shortfall from all market participants paying charges or receiving refunds for the historical period through the Module C settlement process by way of an adjustment of loss factors using Rider E, where any default shortfalls are recovered as a cost of losses. The AESO shall collect by way of Rider E on a going forward basis, any subsequent payment default shortfalls, as they become known, from all market participants, regardless of whether the market participant received a charge or refund for the historical period.

NATIONAL ENERGY BOARD

NOVA Gas Transmission Limited – Albersun Pipeline Asset Purchase Project (NEB Report GHW-001-2016)
Pipeline Acquisition – Acquisition Cost in Rate Base

On April 27, 2016, NOVA Gas Transmission Ltd. ("NGTL") applied to the NEB seeking leave to purchase the Albersun Pipeline (the "Project") from Suncor and include the cost in the NGTL System rate base, pursuant to Parts IV and V of the *National Energy Board Act*, and for a Certificate of Public Convenience and Necessity for the Albersun Pipeline, among other things, dated 27 April 2016.

Economic, Financial and Accounting Matters

An applicant making an application pursuant to section 52 of the *NEB Act* is expected to demonstrate the economic feasibility or need for the project, any alternatives to the project that have been evaluated and considered, the justification for the project over other possible options, the likelihood of the pipeline being used at a reasonable level over its economic life, and the justness and reasonableness of the proposed tolls.

With respect to the economic feasibility of a project, the NEB assessed the need for the Project and the likelihood of it being used at a reasonable level over its economic life. Specifically, the NEB considered:

(a) the supply of product available and the transportation contracts underpinning the facilities;

(b) the availability of adequate markets to receive the product to be delivered by the pipeline, and the adequacy of the pipeline's capacity; and

(c) the applicant's ability to finance the proposed facilities.

The NEB found that NGTL had sufficiently demonstrated the economic feasibility of the project, based on the following findings:

(a) there was adequate supply and markets to support the ongoing use of the Albersun Pipeline;

(b) the NGTL system provided sufficient supply to service shippers with delivery points on the Albersun Pipeline and forecasts indicated growth in gas supplies over the forecast period ending 2028;

(c) with respect to demand, shippers had expressed an interest in renewing their FT-D contracts for delivery to market areas served by the Albersun Pipeline, and NGTL illustrated that nearly all of the capacity available on the pipeline would be contracted over the forecast period ending 2028;

(d) Albersun Pipeline was the least cost solution for providing delivery service to the Fort McMurray markets; and

(e) NGTL was capable of financing the purchase of the pipeline through its parent company, TransCanada, which has sufficient access to financial markets.

Financial Matters

The NEB approved NGTL's request to include the purchase price of the Albersun Pipeline in the Alberta System rate base.

The NEB explained that, in assessing a company's proposal to add a facility's acquisition costs to its rate base, the NEB considers the relevant circumstances and specific facts of the proposal. Such facts may include the purchase price of the facility in relation to its depreciated original cost, whether the negotiations for the purchase price were conducted at arm's length, the availability of lower-cost transportation alternatives, and the impacts on shippers' tolls and transportation service.

NGTL confirmed that the purchase price of the Albersun Pipeline exceeded its depreciated original cost.

The NEB found that:

(a) the purchase of the pipeline represented the least cost alternative for providing delivery service to the Fort McMurray area;

(b) the purchase price of the pipeline was determined through arm's-length negotiations; and

(c) the acquisition costs would be spread among all NGTL's system, but the increase to NGTL's revenue requirement would be almost entirely offset by the corresponding cost reduction associated with the terminated TBO arrangement, no longer required as a result of the acquisition.

Environmental and Socio-Economic Matters

The NEB explained that it considered environmental protection as a component of the public interest.

The NEB assessed the potential adverse environmental and socio-economic effects, as well as the adequacy of the NGTL's proposed environmental protection strategies and mitigation measures. Where there are any residual effects remaining after proposed mitigation, the NEB considered cumulative effects.

Mitigation of Potential Adverse Environmental Effects

The NEB noted:

(a) NGTL's commitment to avoid the migratory bird breeding period and the caribou restricted access period;

(b) NGTL's commitment that no new access to the East Side Athabasca Caribou Range would be created; and

(c) NGTL's commitment to adhering to the recommendations and mitigation measures set out in the Environment and Socio-Economic Assessment (ESA) and in the Environmental Protection Plan (EPP), filed with the NEB.

The NEB found that:

(a) no new or increased residual effects would be expected as a result of the Project;

(b) there would be no additional or increased interactions with biophysical or socio-economic elements as a result of continued operation of the Albersun Pipeline under NGTL ownership; and

(c) NGTL's commitment to adhering to the mitigation measures set out in the ESA and EPP was adequate.

Cumulative effects

The NEB found that no new or increased contributions to cumulative effects were likely to occur as a result of the Project.

Environmental Assessment Conclusion

The NEB found that the Project was unlikely to result in new or increased interactions between the Project and the environment, new or increased environmental or socio-economic effects, and new or increased contributions to cumulative effects.

The Board is of the view that overall, with the implementation of NGTL's environmental protection procedures and mitigation and the NEB's recommended conditions, the Project is not likely to cause significant adverse environmental effects.

NOVA Gas Transmission Limited – Application for the Sundre Crossover (Decision and Order with Reasons to Follow GH-002-2017)
Application to Construct and Operate Pipeline – Decision with Reasons to Follow

On 24 March 2017, NOVA Gas Transmission Ltd. ("NGTL") applied to construct and operate the Sundre Crossover Project (the "Project") pursuant to section 58 of the *National Energy Board Act* ("*NEB Act"*) and section 45.1 of the National Energy Board Onshore Pipeline Regulations ("*OPR"*) (the "Application"). In the Application, NGTL also requested exemptions from paragraph 30(1)(a) and section 31 of the *NEB Act*.

The NEB issued this decision with reasons to follow.

The Board approved the Project and issued Order XG-N081-030-2017, and associated conditions pursuant to section 58 of the *NEB Act* and section 45.1 of the *OPR*, respectively. The NEB granted NGTL the relief requested with respect to paragraph 30(1)(a) and section 31 of the *NEB Act*.