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REGULATORY
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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 Vincent Light at Vincent.Light@RLChambers.ca.

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REFLECTIONS ON THE CLIMATE LEADERSHIP PLAN

On November 22, 2015, Premier Rachel Notley announced Alberta's new Climate Leadership Plan ("CLP"), based on recommendations for an Alberta climate change policy set out in the report of the Climate Leadership Panel ("Panel Report"). One of the four key initiatives of the CLP is the phase-out of coal-generated electricity by 2030 and the development of renewable energy in its place.

RLC sat down with Erica Young, the Calgary-based VP & General Counsel of renewable energy company NaturEner, an RLC client,[1] to discuss the CLP and the impact that the announcement has already had on investor interest in Alberta.

Q. What is NaturEner's reaction to the CLP and what it means for renewable energy development in Alberta?

A. We are encouraged by the commitment that the Government is making to tackle climate policy and to phase-out coal-fired electricity generation[2], replacing the majority of it with clean, non-emitting, renewable energy.[3] Moving the needle for wind generation from 4% today towards 30% by 2030 is an ambitious but achievable goal.

The Government is currently developing the details that underpin the broad policy announcements, so we don't have enough visibility to provide many substantive comments. Other than the fact that renewable energy will be supported through "auctioning", the Government has not yet made public the specifics of its renewable energy program.

Having said that, based on recommendations in the Panel Report and comments made to industry, we expect that the program will include a competitive offer process, pursuant to which projects would be awarded long-term purchase agreements for the "green attributes" generated by renewable energy projects. We have a lot of questions about timing and staging, contract term, volumetric commitments, pricing, credit support and assessment criteria. The energy would still be sold into the Alberta market.

The Government deserves credit for not shying away from the challenges of this file. Addressing climate policy while maintaining the integrity of the Alberta market will be a real achievement.

Q. Have you seen the level of investor interest in Alberta increase since the announcement of preliminary details of the CLP? What has been the reaction of potential investors in conversations with NaturEner?

A. We have definitely seen increased interest since early fall. There has been a growing sense that the new Government was going to act on climate change and renewable energy investors from around the world have been watching. NaturEner has two fully-permitted utility scale wind farms that are high up in the AESO interconnection queue, which is a public report. There are not very many wind projects that could move forward to construction in the 2017-2018 timeframe and NaturEner's Wild Rose 1 and Wild Rose 2 projects are the largest ones in that position. In general, I would say that the announcement of the CLP has created a great deal of potential and opportunity in the Alberta marketplace, with most potential investors taking a "wait and see" approach at this point. More detail is required regarding the timing and key terms of the program.

Q. Where is the interest coming from? Is it predominately Alberta companies?

A. There is some interest from the incumbent generators in Alberta but it's much broader than that. We have been contacted by North American, Asian and European groups that I would categorize as energy companies, strategics and pure financial players. Some are balance sheet players and some require project finance structures. Parties who rely on project finance may struggle with the "unbundled product" the Government is proposing. Alberta is a unique

1 RLC successfully represented NaturEner in connection with approvals for its Wild Rose 2 wind project, the first AUC hearing for a wind farm power plant approval. RLC has also acted for NaturEner in market rule hearings and appeals, most recently before the AUC and the Alberta Court of Appeal, related to the mechanism for sharing import capacity into Alberta.

2 The CLP accelerates end-of-life for some Alberta coal plants by requiring them to cease operations by 2030. Some coal plants were already scheduled to cease operations under existing federal regulations, with the first of these shutting down at the end of 2019.

3 In 2014, 55% (44k GWh) of total electricity generation in Alberta (80k GWh) was produced by 18 coal generators, while only 4% (<4k GWh) was produced by wind generators. (Source: Alberta Energy)

jurisdiction that can present challenges in terms of forward liquidity in the power markets. Those with experience or deep knowledge of the Alberta market understand clearly the implications of the proposed structure in this context.

Q. Recognizing that the Panel Report is just a set of recommendations, what is your reaction to the suggestion of a $35/MWh price ceiling for green attributes?

A. The Government wants to manage the cost of the program, which is understandable and necessary. Without commenting on whether that number is the right one, the experience of other jurisdictions has been that collars tend not to be adjusted frequently, even though the overall levers of project economics may change rapidly. Studies also show a tendency to bid at a discount to the collar, such that the resulting transaction price may be higher than if no number were given.

There are only a handful of key inputs that determine whether a project will be economically viable and these inputs change over time. Applying the low energy prices we're seeing in the forward curve now, project economics for all new build generation, not just for wind, is challenging. Two years ago, projects could have priced green attributes much lower than they will be able to today because of higher energy prices at that time as well as the stronger Canadian dollar.[4] I think a competitive process to ensure uptake of the most competitively priced green attributes, combined with the ability to manage the timing of incremental additions, will be the best way for the Government to maintain control.

By the way, this doesn't necessarily mean the lowest offered priced for green attributes. A project that requires system-funded transmission upgrades could effectively have a higher overall cost to Albertans than a project whose green attributes are slightly more expensive but can connect to existing transmission infrastructure. The challenge will be resolving any transmission cost implications with the obligation of the AESO to plan a system to accommodate all in-merit energy. It will be interesting to see how, and whether, this piece is addressed once details are released.

Q. Albertans don't want to read the types of headlines coming out of Ontario with respect to the cost and management of the *Green Energy Act* there. How do you think the Government can avoid that?

A. On December 2, 2015, the Auditor General reported that Ontarians have already paid $37 billion more than market price for electricity, with another $133 billion coming between now and 2032. For me, the big take-away is the conclusion that what drove those costs, for the most part, was the Government interfering in decisions made by the purported independent agencies charged with planning and operating the Ontario electric system. The Government ignored the advice of the experts and instead, for example, approved (and cancelled) projects in response to heavy lobbying and political considerations.

Alberta has highly qualified and experienced people at the AESO and the AUC. The Government should rely on the ability of these experts to plan and operate, and evaluate and approve, respectively, the components of an efficient and reliable electric system.

[4] For many projects, a significant component of capex is exposed to currency risk prior to construction.

ALBERTA COURT OF APPEAL

O'Chiese First Nation v Alberta Energy Regulator (2015 ABCA 348)
Leave to Appeal – Dismissed

The O'Chiese First Nation applied for leave to appeal to the Alberta Court of Appeal (the "ABCA"), to appeal two decisions of the AER:

(a) One dated July 9, 2015 (the "Rocky 5 and Rocky 6 Decision"); and

(b) Another dated July 9, 2015 (the "Rocky 24 Decision").

(collectively, the "Decisions").

Shell Canada Limited ("Shell") had applied to the AER for approval of two natural gas pipelines, ("Rocky 5" and "Rocky 6").

Shell also applied for a mineral surface lease for a petroleum and natural gas well site and a licence of occupation for the use of a road, both under the *Public Lands Act and* under the Enhanced Approval Process which allows for streamlined applications and abbreviated timelines (collectively, "Rocky 24").

The O'Chiese First Nation is located approximately 20 kilometers from the lands to which the Decisions apply. The O'Chiese First Nation argued that its aboriginal treaty rights would be directly and adversely affected by any development within the O'Chiese First Nation Consultation Area. This area was established by the Department of Aboriginal Affairs for the Government of Alberta to assist in discharging the duty to consult. A main point of the O'Chiese First Nation's argument was that once a development had taken place, its traditional treaty rights are lost over the area of the development.

The AER had originally held in the Rocky 5 and Rocky 6 Decision that the O'Chiese First Nation was not eligible to request a regulatory appeal pursuant to section 36 and 38 of the *Responsible Energy Development Act* (the "*REDA*"), on the basis that the O'Chiese First Nation was not a person directly and adversely affected by an "appealable decision".

In the Rocky 24 Decision, the AER similarly held that the O'Chiese First Nation was not directly and adversely affected by the decision rendered under the *Public Lands Act*.

The AER, in rendering the Rocky 5 and Rocky 6 Decision, held that the concerns raised by the O'Chiese First Nation were general in nature, and did not provide sufficient information to the AER to demonstrate how any potential approval may directly and adversely impact them. The AER also held that the O'Chiese First Nation was required to establish some degree of location or connection between the work proposed and the rights asserted, which the AER characterized as a question of fact.

The O'Chiese First Nation submitted that the AER erred in law in ruling that the O'Chiese First Nation was not eligible to request a regulatory appeal on the grounds that the O'Chiese First Nation was not directly and adversely affected by the AER's issuance of the Decisions.

McDonald J.A. cited the appropriate test for leave to appeal from the AER as being governed by section 45(1) of the *REDA*, which limits appeals to the Alberta Court of Appeal to questions of law or jurisdiction. McDonald J.A. also cited a four point test developed by Hunt J.A. in *Bearspaw Petroleum Ltd. v Alberta Energy and Utilities Board* which provides that an application for leave to appeal must demonstrate a serious arguable point, including:

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

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

(c) Whether the appeal is *prima facie* meritorious or frivolous; and

(d) Whether the appeal will unduly hinder the progress of the action.

McDonald J.A. did not analyze at length the application of defined terms such as "eligible person" in the *REDA* in determining whether the O'Chiese First Nation was indeed an eligible person. The primary reason being that the O'Chiese First Nation adduced no evidence whatsoever with respect to how its treaty rights would be impacted by the Decisions.

However, the O'Chiese First Nation acknowledged this, arguing that any development within its consultation area was evidence in and of itself of the loss of its traditional treaty rights within the development itself.

While the O'Chiese First Nation submitted that its question on appeal was a question of law, McDonald J.A. determined that the AER in effect applied a legal standard to a specific set of facts. Therefore, the question on appeal was characterized as one of mixed fact and law, and therefore not capable of forming the basis of an appeal to this court under section 45(1) of the *REDA*.

McDonald J.A. held that a decision of the AER, as a matter of fact, can directly and adversely affect a party, but that such a determination must be considered in light of the evidence and facts before it. Therefore the words "directly and adversely affected" are not strictly engaged as a matter of law.

McDonald J.A. held that while the appeal itself was important, it ultimately fell short by conflating the findings of the AER that the O'Chiese First Nation was not directly and adversely affected under the statutory language of the *REDA* and the *Public Lands Act*, with the adequacy of the Crown's duty to consult.

In the result, McDonald J.A. held that the O'Chiese First Nation had not raised a "serious arguable point" in the matter, as it had failed to adduce any evidence before the AER on the matter, and accordingly dismissed both applications.

ALBERTA ENERGY REGULATOR

Results of AER Dam Safety Inspections Released (NR2015-22)
Dam Safety Inspection

The AER released the results of its dam safety inspections held earlier this year. The AER made commitments as a result of the Auditor General's report on dam safety in Alberta (available here). The AER assumed responsibility for the regulation of all containment structures used in the development of Alberta's energy resources such as oil sands and coal mines, and associated tailings ponds. The regulation of the remainder of Alberta's dams rests with Alberta Environment and Parks' Dam Safety department.

The AER noted that containment, in its review, included inspections of structures such as dams, liquid impoundments (including oil sands tailing ponds), coal tailings ponds, and oil and gas fluid storage ponds. The AER inspected 100 of the 111 containment structures that it regulates. The inspections of 55 oil sands structures and 14 oil and gas structures did not identify any significant deficiencies. Inspections of 31 coal mine structures found that one structure owned by Coal Valley Resources was significantly deficient due to erosion within the structure.

The AER noted that it would be investigating the non-compliance, and would release the results of its investigation at a later date.

The AER stated that 11 structures were not inspected, as 9 were only recently approved for start of construction, and that the remaining 2 structures were considered low risk and are slated to be inspected next year.

ALBERTA UTILITIES COMMISSION

City of Medicine Hat Modification to Electric Distribution Service Area (Decision 20828-D01-2015)
Electric Distribution Service Area Amendment

The City of Medicine Hat ("Medicine Hat") applied to the AUC pursuant to sections 25 and 29 of the *Hydro and Electric Energy Act* to amend its electric distribution service area to include an additional 2.59 hectares. The proposed amendment would include the final phase of the Desert Blume residential development consisting of 83 residential lots. Medicine Hat stated that 62 of the lots fell within its service area, 13 of the lots fell within the service area of FortisAlberta Inc., and the remaining 8 lots straddled the boundary between the two service areas.

Medicine Hat submitted the application pursuant to a request from the developer that the development be serviced by a single electric distribution system. FortisAlberta Inc. supported the application, noting that the majority of the development was within Medicine Hat's service area.

The AUC agreed with Medicine Hat, finding that the residential development of Desert Blume would be better served by a single electric distribution service provider. The AUC found that this would provide consistent service to affected residents, and would be in the public interest. The AUC therefore ordered that Medicine Hat's distribution service area be modified to include the Desert Blume residential development.

Alberta Electric System Operator Request for Consent to Terminate the Reliability Management System Agreement and the Western Electricity Coordinating Council Reliability Criteria Agreement (Decision 20840-D01-2015)
Termination of Agreements – Request for Consent

The Alberta Electric System Operator ("AESO") applied for consent from the AUC to terminate the Western Electricity Coordinating Council ("WECC") Reliability Criteria Agreement and the Reliability Management System Agreement (collectively, the "Agreements") pursuant to section 21(1)(b) of the *Transmission Regulation*.

The AESO submitted that it was seeking to terminate the Agreements because they were no longer needed. The original purpose of the Agreements was to ensure that transmission reliability requirements would be met through voluntary adherence to reliability standards incorporated into the Agreements. However, since 2009, all of the reliability standards in the Agreements have been incorporated into Alberta reliability standards, or were determined non-applicable in Alberta by the AESO. As a result, transmission operators in Alberta terminated their respective Reliability Criteria Agreements with WECC, leaving WECC and the AESO as the sole remaining signatories to the Agreements. The AESO further submitted that WECC had agreed to terminate the Agreements.

The AUC accepted the AESO's submissions, relying on the representations made by the AESO in finding that the Agreements were no longer needed. The AUC gave its consent pursuant to section 21(1)(b) of the *Transmission Regulation* for the AESO to proceed with terminating the Agreements.

Alberta Electric System Operator Application for AESO 2015 Transmission Constraint Rebalancing Charge and Approval to Amend the ISO Tariff Pursuant to Decisions 2013-135 and 3528-D01-2015 (Decision 20623-D01-2015)
Transmission Constraint Rebalancing Charge – ISO Tariff Amendment

The Alberta Electric System Operator ("AESO") applied to the AUC for approval of amendments to demand transmission service ("Rate DTS"), Fort Nelson demand transmission service ("Rate FTS") and its deferral account adjustment rider ("Rider C") in the Independent System Operator tariff (the "ISO Tariff").

The AESO submitted that approval of its application would enable the recovery of transmission constraint rebalancing ("TCR") costs through the ISO Tariff. The AESO submitted that TCR costs are incurred when the interconnected electric system lacks the capability to deliver electricity to a given load area without contravening system reliability requirements. The purpose of TCR is to restore the energy balance on the interconnected electric system downstream of a system constraint.

The AESO proposed to recover TCR costs from Rate DTS and Rate FTS, as these are the primary rates used in the ISO Tariff to recover costs from load market participants. The AESO excluded TCR cost recovery from demand opportunity service and export opportunity merchant service, on the basis that the applicable incremental costs are expressed as a fixed $/MWh amount which is not subject to hourly variation.

TCR payments are made to market participants in accordance with the recently revised Section 302.1 of the ISO rules, *Real Time Transmission Constraint Management* (the "TCM Rule") as set out in Decision 3528-D01-2015. The AESO had originally been directed to revise the TCM Rule as a result of Decision 2013-135. The AESO, in turn, proposed to use TCR as a replacement for "real-time transmission must run" to avoid conflating "real-time transmission must run" with "transmission must run" in the ISO Tariff.

The AESO submitted that the recovery of the TCR costs was assessed to be consistent with principles of cost causation as it is a primary consideration in rate design. The AESO noted that, pursuant to section 47(a)(i) of the *Transmission Regulation*, since these costs arise for transmission reasons and are costs of the transmission system, they are charged to load under the ISO Tariff.

The AESO noted that transmission outages do not correlate strongly to periods of peak system loads, and therefore submitted it would not be appropriate to recover TCR costs based on coincidence with system peak usage. As a result, the AESO proposed to recover TCR costs through a usage charge (charged in $/MWh). The AESO reasoned that a fixed usage charge would provide a price signal in all hours, including those in which constraints occur, which may lead to reduced energy consumption in hours where transmission constraints occur. The AESO submitted that this would allow market participants to respond by making decisions to maintain or adjust usage based on the value of service received.

The AUC held that the proposed adjustments for recovery of TCR charges were reasonable on the basis that:

(a) The adjustments would provide a clearer and more transparent price signal;

(b) The adjustments would apply equally to Rate DTS and Rate FTS;

(c) TCR costs are properly classified as transmission costs and must therefore be charged to load customers under the ISO Tariff; and

(d) The AUC was satisfied with the AESO stakeholder consultation respecting the recovery of TCR costs through the ISO Tariff.

Accordingly, the AUC approved the AESO's proposed ISO Tariff amendments to implement a TCR cost effective November 26, 2016 on a final basis.

Direct Energy Regulated Services Application for a Single Gas Cost Flow-through Rate (Decision 20363-D01-2015)

Single Gas Cost Flow-through Rate

Direct Energy Regulated Services ("DERS") applied for approval of a single gas cost flow-through rate ("GCFR") for its Rider F rate to regulated rate option customers on the ACTO Gas North and ATCO Gas South systems. DERS performs the natural gas default rate tariff and regulated rate tariff on behalf of ATCO Gas and Pipelines Ltd. ("ATCO") in ATCO's service areas as the default service provider ("DSP"). DERS had previously submitted GCFR applications for the North and South service areas since taking over the DSP role in 2004. However, with the recent integration of the pipelines division of ATCO into the Nova Gas Transmission Ltd. system in Alberta, DERS submitted that separate rates for the North and South areas were no longer needed.

DERS submitted that the single GCFR would be calculated using the same methodology as currently employed, but on a province-wide basis. DERS submitted that a single GCFR, though it would not likely create a cost savings, would be beneficial for the further evolution of the gas marketplace in Alberta. DERS submitted that the simplicity of the single rate would allow customers to more easily weigh their options in the market. DERS also noted that the North and South rates were 96 percent correlated, and therefore the transition to a single rate would not have a significant price impact for either set of customers.

The City of Calgary ("Calgary") stated that it did not oppose the single GCFR, however, requested that the AUC confirm that the single GCFR would have no bearing or impact on the continuation of separate distribution rates for North and South customers of ATCO. Calgary also requested that the AUC direct DERS to provide an analysis of potential cost savings from the switch to the single GCFR in its next general rate application.

DERS responded to Calgary by noting that the single GCFR proposal was not related to ATCO's distribution rates, and therefore ATCO's rates did not impact the GCFR rates charged by DERS.

With respect to Calgary's request, the AUC held that the appropriate forum to test whether or not the single GCFR has resulted in any cost savings is in DERS' next general rate application. Therefore, the AUC directed DERS to report on any resultant cost savings in its next general rate application.

The AUC determined that the changes to the natural gas market, particularly with respect to the integration of regulated gas transmission in Alberta, the creation of a province-wide unaccounted for gas rate, and a province-wide load balancing deferral account, were all indicative of a need to switch to a single province-wide GCFR. Accordingly, the AUC approved DERS' application as filed.

EPCOR Distribution & Transmission Inc. 2014 Annual Transmission Access Charge Deferral Account True-up (Decision 201719-D01-2015)
Deferral Account True-up

EPCOR Distribution & Transmission Inc. ("EPCOR") applied to the AUC for approval of its 2014 transmission access charge deferral accounts ("TACDA") true-up, which it proposed to collect through Rider J. Each electric distribution company is charged by the Alberta Electric System Operator ("AESO") for transmission services in relation to customers in their distribution service areas. EPCOR's TACDA collects these charges as a flow-through of the AESO's tariff charges during its performance based regulation term.

EPCOR submitted that pursuant to section 14(3) of the *Electric Utilities Act*, the AESO must be managed so that no profit or loss results from its operation on an annual basis, thereby necessitating the current application to true-up these amounts.

Among the items requested for collection in the proceeding, EPCOR requested the recovery of the following:

Component	**True-up amount ($)**	**Methodology to attribute amounts to rate classes**
Deferral account rider true-up	272,175	Difference between amounts approved for collection/refund by rate class and the amount actually collected/refunded for each rate class.
2014 system access service (SAS) deferral true-up	1,036,641	AESO costs allocated to rate classes using EPCOR's cost of service methodology.
AESO deferral account reconciliation (DAR) true-up	0	
2014 Balancing Pool true-up	(27,822)	Allocated to rate classes using actual energy from 2014 based on ECPOR latest version of 2014 settlement.
Carrying costs	34,937	Allocated to rate classes based on their proportion of the deferral balances.
Quarter (Q) 4 2013 true-up	65,693	Difference between amounts approved for collection/refund by rate class and the amount actually collected/refunded for each rate class.
Total	1,381,621	

EPCOR proposed to collect its TACDA true-up and Q4 2013 true-up amounts through Rider J, effective from April 1, 2016 to June 30, 2016. EPCOR also requested approval for the extension of the annual deadline to file its TACDA true-up application from August 10 to August 17 each year.

The AUC accepted each of EPCOR's calculations as filed, noting that the cost allocation methodologies were reasonable, or were previously approved by the AUC in prior decisions. The AUC therefore approved a net collection of $1,381,621 to be collected by EPCOR through Rider J.

With respect to the implementation period for the collection of the TACDA, EPCOR requested that the collection period begin in April of 2016 rather than in January of 2016, as it originally expected an approval of Q1 2016 for the current proceeding. However, EPCOR submitted that given the new timing possibilities, it would prefer a collection period starting on January 1, 2016, as the collection period would coincide with Rider DJ, which is a net refund, and would therefore reduce customer bill impacts. EPCOR submitted that a three-month collection period would result in a maximum change to customers' monthly bills of 9.27 percent, and would therefore not constitute a rate shock.

The AUC agreed with EPCOR's submissions, holding that coordinating the collection period of Rider J with Rider DJ would reduce the total bill impact for consumers, and noted that the proposed three-month collection period would not result in rate shock.

With respect to the deadline extension for the annual application of its TACDA, EPCOR submitted that a one-week extension to August 17 would allow enough time for EPCOR to incorporate final revenue information from the second quarter of the current fiscal year, thereby eliminating the need for future true-up applications for those quarters.

The AUC approved EPCOR's request for an extension to the deadline for TACDA filings, holding that such an extension may create efficiencies.

The AUC therefore directed EPCOR to recover $1,381,621 through Rider J to be effective from January 1, 2016 to March 31, 2016.

ATCO Electric Ltd. 2014 Annual Transmission Access Charge Deferral Account True-up (Decision 20705-D01-2015)

Transmission Access Charge Deferral Account True-up

ATCO Electric Ltd. ("ATCO") applied to the AUC for approval of its 2014 transmission access charge deferral accounts ("TACDA") true-up, which it proposed to collect through Rider G. Each electric distribution company is charged by the Alberta Electric System Operator ("AESO") for transmission services in relation to customers in their distribution service areas. ATCO's TACDA collects these charges as a flow-through of the AESO's tariff charges during its performance based regulation term.

ATCO applied for a net 2014 TACDA refund of $4.225 million, set out as follows:

Component	**True-up amount (million $)**	**Methodology to attribute amounts to rate classes**
2013 TACDA true-up	(0.005)	Difference between amounts approved for collection/refund by rate class and the amount actually collected/refunded for each rate class.
2014 system access service (SAS) deferral true-up	(4.823)	AESO costs allocated to rate classes using ATCO's cost of service methodology.
AESO deferral account reconciliation (DAR) true-up	0	
2014 Balancing Pool true-up	0.935	Allocated to rate classes, excluding Rate T31, in proportion to the Balancing Pool amount actually collected/refunded.
Carrying costs	(0.332)	Allocated to rate classes based on their proportion of the deferral balances.
Total	(4.225)	

ATCO proposed to refund the 2014 TACDA effective from January 1, 2016 to December 31, 2016.

The AUC accepted ATCO's calculations as reasonable noting that the cost allocation methodologies were also reasonable, or were previously approved by the AUC in prior decisions. The AUC directed ATCO to identify any under-frequency load shedding credit amounts as a separate column in its future TACDA applications.

ATCO submitted that a twelve-month collection period would result in a maximum change to customers' monthly bills of 3.3 percent, and would therefore not constitute a rate shock. The AUC agreed with ATCO's submissions.

Accordingly, the AUC approved ATCO's application as filed, to refund $4.225 million to customers effective January 1, 2016 to December 31, 2016.

FortisAlberta Inc. 2014 Annual Transmission Access Charge Deferral Account True-up (Decision 20666-D01-2015)

Transmission Access Charge Deferral Account True-up

FortisAlberta Inc. ("FAI") applied to the AUC for approval of its 2014 transmission access charge deferral accounts ("TACDA") true-up, which it proposed to collect through a base 2016 transmission adjustment rider ("2016 TAR"). Each electric distribution company is charged by the Alberta Electric System Operator ("AESO") for transmission services in relation to customers in their distribution service areas. FAI's TACDA collects these charges as a flow-through of the AESO's tariff charges during its performance based regulation ("PBR") term.

FAI applied for a net 2014 TACDA refund of $10.917 million, set out as follows:

Component	**True-up amount (million $)**	**Methodology to attribute amounts to rate classes**
2012 TACDA true-up	0.623	Difference between amounts approved for collection/refund by rate class and the amount actually collected/refunded for each rate class.
2014 system access service (SAS) deferral true-up	(12.669)	AESO costs allocated to rate classes using FAI's cost of service methodology.
AESO deferral account reconciliation (DAR) true-up	0	

2014 Balancing Pool true-up	1.625	Allocated to rate classes using actual energy from 2014.
2014 border customer deferral account true-up	0.190	Allocated to rate classes using actual energy from 2014.
Carrying costs	(0.686)	Allocated to rate classes based on their proportion of the deferral balances.
Total	(10.917)	

FAI proposed to refund the 2014 TACDA true-up amount by way of its 2016 TAR, effective January 1, 2016 to December 31, 2016.

The AUC accepted FAI's calculations as reasonable noting that the cost allocation methodologies were also reasonable, or were previously approved by the AUC in prior decisions.

FAI submitted that its 2016 TAR would take the form of a percentage of the base transmission access charges that form part of its distribution tariff. Therefore the TACDA amount for each rate class, according to FAI, would be divided by the forecast base 2016 transmission access charge amount. Accordingly, FAI stated that it did not calculate the 2016 TAR rates, as the base 2016 transmission access charges would be determined as part of FAI's 2016 annual PBR rate adjustment application.

The AUC approved FAI's application as filed, to refund $10.917 million to customers effective January 1, 2016 to December 31, 2016 through a percentage-based transmission adjustment rider methodology to be determined as part of FAI's 2016 annual PBR rate adjustment application.

EPCOR Distribution & Transmission Inc. 2013 Generic Cost of Capital Compliance Filing (Decision 20692-D01-2015)

Compliance Filing - Generic Cost of Capital

EPCOR Distribution & Transmission Inc. ("EDTI") filed its compliance filing with the AUC pursuant to directions made in Decision 2191-D01-2015, which was the 2013 Generic Cost of Capital ("GCOC") proceeding. In that decision, the AUC ordered that:

(a) The final approved return on equity ("ROE") for 2013, 2014 and 2015 was 8.30 percent; and

(b) The final approved deemed equity ratio for EDTI's transmission functions for 2013, 2014 and 2015 was 36 percent.

The AUC therefore directed that any utilities using an ROE value and capital structure during the same period on a placeholder basis must apply to the AUC by July 31, 2015 to adjust their revenue requirements to reflect the approved ROE values and capital structures. As a result, EDTI requested revenue requirement reductions in the amounts of $0.90 million for 2013 and $1.34 million for 2014. EDTI also requested approval of its true-up mechanism for refunding the amounts.

EDTI submitted that it used the AUC-approved ROE values of 8.30 percent for each of 2013, 2014 and 2015 to update its calculations for the return on mid-year rate base. EDTI however, did not use the AUC-approved figures of 36 percent for its equity component, instead using equity ratios of 36.40 percent (2013), 36.27 percent (2014) and 36.22 percent (2015) to update its calculations for the return on mid-year rate base. EDTI submitted that the debt and equity ratios in its application were the same methodology used to determine the debt and equity ratios in its 2013-2014 transmission facility owner refiling application. EDTI explained that the variance from the approved 36 percent equity ratio was due to the calculation of the revenue requirement based on its forecast balance sheet, and the fact that EDTI's issuances of debt and equity, which occur in the millions of dollars, do not exactly match the approved ratios when calculated to two decimal places. EDTI submitted that its practice was previously approved by the AUC, and was consistent with past practice.

The AUC noted that in Decision 3539-D01-2015, it had already determined that EDTI must refile its application to reflect the approved debt and equity ratios of 64 percent and 36 percent, respectively. The AUC dismissed EDTI's requested variances to the approved ROE figures. The AUC communicated that it dedicates significant regulatory resources to consider and determine the generic cost of capital for regulated Alberta utilities, and held that companies such as EDTI could not unilaterally substitute self-derived capital structure values for their forecast revenue requirements. The AUC also held that this principle applies regardless of whether companies complied with the AUC's ROE and capital structure findings previously, noting that past practice cannot be used as a basis upon which to validate current or future non-compliances.

Accordingly, the AUC held that EDTI's use of the ROE of 8.30 percent as determined in Decision 2191-D01-2015 was reasonable. However, the AUC held that EDTI did not comply with its direction in Decision 2191-D01-2015 to reflect the AUC-approved debt and equity ratios of 64 and

36 percent, respectively, and therefore ordered EDTI to refile using the approved figures.

In view of the connected and similar nature of the compliance filing directed here, and in Decision 3539-D01-2015 concerning ROE and debt and equity ratios, the AUC directed EDTI to file its compliance filing jointly for these two matters. The AUC directed that the compliance filing be filed on or before January 4, 2016.

The AUC further directed EDTI, beginning in 2015, to make its filings pursuant to AUC Rule 005: *Annual Reporting Requirements of Financial and Operational Results* using AUC-approved figures for ROE and debt and equity ratios.

Stakeholder Consultation on AUC Rule 002: Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors (Bulletin 2015-17)
Bulletin – Rule 002

The AUC announced that it invited comments on proposed revisions to AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors* ("*Rule 002*"). The AUC noted that the proposed revisions are the product of consultations with electric and gas utilities, as well as the Office of the Utilities Consumer Advocate and the Industrial Power Consumers Association of Alberta.

The proposed revisions, available for review here, were open for comment until November 24, 2015. The AUC noted that it will proceed to finalize the proposed revisions to *Rule 002* prior to January 1, 2016.

Revision of AUC Rule 019: Specified Penalties for Contravention of ISO Rules (Bulletin 2015-18)
Bulletin – Rule 019

The AUC announced that it approved amendments to AUC Rule 019: *Specified Penalties for Contravention of ISO Rules* ("*Rule 19*"). The amendments became effective on December 7, 2015.

The AUC indicated that its normal practice in the past has been to invite comments from market participants on any possible amendments to *Rule 19*. However, in this instance, the AUC explained that the changes were administrative in nature, and did not necessitate a consultative process. The AUC stated that the most recent changes related to the penalty tables that divide the various contraventions into different categories, to reflect the redrafting of certain ISO rules by the Alberta Electric System Operator ("AESO").

As part of the Transition of Authoritative Documents ("TOAD") project, the AESO removed ISO rules 3.6.2, 3.6.3, 6.4.3, 6.5.2, 6.5.3, OPP 403, and OPP 404 effective December 23, 2014 and replaced them with the following ISO rules:

(a) Section 205.1: Offers for Operating Reserve;

(b) Section 205.2: Issuing Dispatches and Directives for Operating Reserve;

(c) Section 205.3: Restatements for Operating Reserve;

(d) Section 205.4: Regulating Reserve Technical Requirements and Performance Standards;

(e) Section 205.5: Spinning Reserve Technical Requirements and Performance Standards; and

(f) Section 205.6: Supplemental Reserve Technical Requirements and Performance Standards.

Accordingly, the AUC amended the penalty table in *Rule 19* to reflect the above changes. A copy of *Rule 19* showing the changes referenced in this bulletin can be found here.

Alberta Electric System Operator Approval of New Alberta Reliability Standards VAR-001-AB-4 and VAR-002-AB-3, and Removal of Alberta Reliability Standards VAR-001-AB-1a and VAR-002-AB-1.1b (Decision 20952-D01-2015)
Alberta Reliability Standards – Approval and Removal

The Alberta Electric System Operator ("AESO") applied to adopt the following Voltage and Reactive ("VAR") reliability standards pursuant to section 19 of the *Transmission Regulation*:

(a) VAR-001-AB-4 Voltage and Reactive Control; and

(b) VAR-002-AB-3 Generator Operation for Maintaining Network Voltages.

The AESO also applied to remove the following VAR reliability standards pursuant to section 19 of the *Transmission Regulation*:

(a) VAR-001-AB-1a Voltage and Reactive Control; and

(b) VAR-002-AB-1.1b Generator Operation for Maintaining Network Voltages.

The AESO stated that the purpose of each respective reliability standard was to ensure that:

(a) Transmission voltage levels, reactive power flows and reactive power resources are monitored, controlled and maintained within limits in real-time to protect equipment and the reliable operation of the interconnection, where interconnection means any one of the three major electric system networks in North America; and

(b) To ensure generating units and aggregated generating facilities provide reactive power and voltage control necessary to ensure voltage levels and to ensure reactive power flows and reactive power resources are maintained within applicable facility ratings to protect equipment and the reliable operation of the interconnection.

The AESO submitted that the new editions of each of the reliability standards were clearer and better aligned with voltage control practices in Alberta, and therefore recommended their adoption and approval with minor administrative amendments.

The AUC held that, pursuant to sections 19(5) and 19(6) of the *Transmission Regulation*, it was obligated to follow the AESO's recommendation to approve or reject a reliability standard unless demonstrated to be technically deficient or not in the public interest. Given that no party filed an objection, the AUC approved each of the proposed reliability standards, effective April 1, 2016. Accordingly, the AUC also approved the removal of the current VAR reliability standards, also effective April 1, 2016.

Alberta Electric System Operator 2015 ISO Tariff Update – Interim Approval (Decision 20753-D01-2015)
ISO Tariff Update

The Alberta Electric System Operator ("AESO") applied to the AUC, pursuant to section 30 and 119 of the *Electric Utilities Act*, for approval of its 2015 Independent System Operator tariff ("ISO Tariff") update. The AESO normally files annual tariff updates as approved in Decision 2010-606.

The AESO requested that the tariff update be approved effective January 1, 2016, and further requested that if a final approval could not be granted prior to that date, that the tariff update be approved on an interim refundable basis on the same date. The AESO noted that it would require an approval by no later than November 16, 2015 in order to test the rates in the AESO's billing system in advance of the proposed January 1, 2016 effective date.

The AESO submitted that its 2015 updated forecast costs represented an increase of $74.9 million (or 4.1 percent) over its 2014 recorded costs, driven primarily from an increase of $136.5 million in wires costs from recent transmission facility owner tariffs. These increases were offset by decreases in other cost components such as ancillary services and other impacts derived from the decreased pool price.

The AESO submitted that the updated forecast costs were made in accordance with the methodologies approved in Decision 2010-606 and in Decision 3473-D01-2015. No objections were raised by parties to the application in respect of the AESO's calculation methods.

The AUC noted that it was not likely to be in a position to issue any decision on a final basis in respect of the AESO's 2015 ISO tariff update in time for the AESO to implement the decision effective January 1, 2016. Accordingly, the AUC approved the application on an interim refundable basis to be effective January 1, 2016, noting that no parties objected to the approval on an interim refundable basis.

The AUC's final decision on the AESO's 2015 ISO tariff update will be provided in due course.

Stakeholder Consultation on AUC Rule 028: Natural Gas Settlement System Code Rules (Bulletin 2015-20)
Bulletin – Rule 028

The AUC announced that it was inviting written comments on proposed revisions to AUC Rule 028: *Natural Gas Settlement System Code Rules* ("*Rule 28*"), which the AUC referred to as version 1.5 of *Rule 28*. The comment period was open to interested parties until noon on November 30, 2015. The AUC noted that it plans to finalize version 1.5 of *Rule 28* prior to January 1, 2016.

A copy of the proposed revisions can be found here.

Stakeholder Consultation on AUC Rule 021: Settlement System Code Rules (Bulletin 2015-19)
Bulletin – Rule 021

The AUC announced that it was inviting written comments on proposed revisions to AUC Rule 021: *Settlement System Code Rules* ("*Rule 21*"), which the AUC referred to as version 2.6 of *Rule 21*. The comment period was open to interested parties until noon on November 30, 2015. The AUC noted that it plans to finalize version 2.6 of *Rule 21* prior to January 1, 2016.

A copy of the proposed revisions can be found here.

AltaLink Management Ltd. Alberta Transmission Facility Owner Terms and Conditions Compliance with Decision 2014-307 (Decision 20882-D01-2015)
Compliant – Transmission Facility Owner

The AUC had originally directed AltaLink Management Ltd. ("AltaLink") to refile an application for approval of a common set of Terms and Conditions ("T&Cs") for Alberta Transmission Facility Owners ("TFOs"), and provide annual progress reports on the Alberta Electric System Operator ("AESO") authoritative documents reform process in Decision 2008-108, and later in Decision 2009-248. This project was undertaken in concert with the AESO's own Transition of Authoritative Documents ("TOAD") initiative.

The AESO's TOAD initiative was completed in June 2013. As a result, AltaLink received approval in Decision 2014-307 to file its 2014 progress report in order to ensure that no TFO T&Cs were missed as a result of the various AESO rule changes throughout the TOAD initiative. The AESO indicated to AltaLink that it required additional time to undertake a review of the various rule changes, and to coordinate such changes with the TFO T&Cs.

AltaLink, on behalf of itself and the other Alberta TFOs, filed a progress report on the efforts to integrate the Alberta TFO T&Cs with the AESO authoritative documents on or before October 1, 2015.

In the application, AltaLink advised that the AESO had completed its review of the T&Cs and authoritative documents, and noted that several provisions may be covered by either an existing AESO document, or by legislation, and noted that several further amendments were planned by the AESO and would be presented for further consultation.

The AUC noted that the information provided by AltaLink and the AESO indicated that changes to authoritative documents were being contemplated that may alter or eliminate several TFO tariff T&Cs. The AUC also noted that the planned dates for consultations on such changes by the AESO would likely occur in 2016.

The AUC expressed its concern with what it referred to as "limited progress" being made with the initiatives, and therefore held that it would not approve the proposed plan to integrate the TFO T&Cs with the AESO authoritative documents. Instead, the AUC determined that it would hear evidence on the status of the process to complete the alignment of the Alberta TFO T&Cs with the relevant AESO authoritative documents as part of AltaLink's 2015-2016 general tariff application hearing. AltaLink's 2015-2016 general tariff application is being heard in December 2015.

ENMAX Power Corporation 2014 Annual Transmission Access Charge Deferral Account True-up Application (Decision 20754-D01-2015)
Transmission Access Charge Deferral Account True-up

ENMAX Power Corporation ("ENMAX") applied for approval of its 2014 annual transmission access charge deferral account ("TACDA") true-up through a rider to its tariff. ENMAX's TACDA application consisted of a net collection of $3,796,899 for the following items:

Component	True-up amount collection/ refund ($)	Methodology to attribute amounts to rate classes
2011-2012 TACDA rider true-up	877,582	Difference between amounts approved for collection/refund and amount actually collected/refunded for each rate class.
2013 TACDA rider true-up (Nov. to Dec.)	94,142	Difference between amounts approved for collection/refund and amount actually collected/refunded for each rate class.
2014 quarterly TACDA riders reconciliation	2,925,316	Difference between amounts approved for collection/refund and amount actually collected/refunded for each rate class.
2014 transmission access charge deferral true-up	(242,563)	Allocated to rate classes based on last approved distribution tariff Phase II allocations.
AESO deferral account reconciliation	0	
2014 Balancing Pool true-up	0	
Carrying costs	142,422	Allocated in proportion to actual energy consumed by each rate class
Total	3,796,899	

ENMAX proposed to collect its TACDA rider effective from January 1, 2016 to March 31, 2016.

ENMAX submitted that its application was not, strictly speaking, a flow through deferral account. ENMAX noted that in accordance with Decision 2014-347, ENMAX was subject to cost-of-service regulation and its TACDA operated as a price-only deferral account. In other words, ENMAX would be kept whole for the AESO's rates at forecast volumes, but bears the risk of billing determinants being higher or lower than forecast. Therefore, rather than comparing total system access service costs compared to actual revenue (i.e. a dollar for dollar true-up), ENMAX calculated the difference between its forecast billing determinants at forecast prices and its forecast billing determinants at actual prices.

As ENMAX did not have approved billing determinants for Q1 of 2016, it requested that the AUC apply the forecast determinants for Q4 2015 as a forecast for Q1 of 2016.

The AUC determined that ENMAX's calculations and allocation methodologies were reasonable, in light of previous directions regarding ENMAX's price-only deferral account. The AUC accepted ENMAX's request to apply the Q4, 2015 forecast billing determinants as Q1 2016 billing determinants for the purposes of this decision, given their proximity to one another. However, the AUC noted that it expects ENMAX in future TACDA true-up applications to use forecast billing determinants approved by the AUC in prior proceedings.

The AUC held that ENMAX applied a simplified method to calculate the Bank of Canada monthly bank rate for the purposes of carrying costs in which the rate changed during a month. While the AUC approved the carrying costs given the relatively small amount, the AUC directed ENMAX to calculate its carrying costs based on the weighted average Bank of Canada monthly bank rate in months in which interest rates may have changed for future TACDA applications.

ENMAX submitted that the maximum bill impact for customers on a monthly basis was 6.9 percent for small commercial customers, and would therefore not cause rate shock. The AUC determined that the changes to typical customer bills were within 10 percent of the total bill and were therefore within a reasonable range and did not constitute rate shock.

The AUC therefore approved ENMAX's net TACDA rider collection of $3,796,899, effective January 1, 2016 to March 31, 2016, as filed.

AltaGas Utilities Inc. 2015-2016 Unaccounted-for Gas Rate Rider E and Rate Rider H (Decision 20806-D01-2015)

Unaccounted-for Gas – Rider E – Rider H

AltaGas Utilities Inc. ("AUI") applied for approval of annual adjustments to its unaccounted-for gas ("UFG") rate riders E and H to its tariff, effective December 1, 2015.

AUI requested to adjust each of its rate riders as follows:

(a) A reduction to Rider E from 1.31 percent to 1.30 percent; and

(b) A reduction to Rider H from 1.33 percent to 1.31 percent.

AUI submitted that it did not propose any change to its previously approved methodology for calculating Rider E and Rider H using five-year arithmetic averages of UFG percentages based on system receipt volumes for Rider E, and delivery percentages for Rider H.

The AUC found that AUI's proposed UFG rate calculations were accurate, and consistent with the previously approved calculation method in Decision 2014-291. The AUC also determined that the percentages for Rider E and Rider H were within the range of the previous five-year historical percentages.

In Decisions 2013-396 and 2014-291, the AUC directed AUI to quantify the causes of UFG, reduce its overall UFG, and take steps to minimize UFG fluctuations from month to month.

AUI, in compliance with Decision 2012-292 and Decision 2014-291, provided:

(a) Monthly data for the period from June 2010 to May 2015;

(b) An explanation for seasonal differences in UFG rates being on account of timing differences in natural gas deliveries and receipts, in addition to low flow metering in the summer months;

(c) An explanation of factors that either positively or negatively impacted UFG volumes throughout the year, including:

  (i) Pipeline leaks; and

  (ii) Incorrect measurements on account of worn, damaged, or failed instruments, as well as maintenance activities on measurement equipment.

The Consumers' Coalition of Alberta ("CCA") submitted that AUI's future applications for UFG rate riders should contain details separated into North, South and Central regions due to the operational differences in AUI's systems. AUI submitted that it would be amenable to providing the requested data.

The CCA also submitted that it was not satisfied with AUI's compliance with the AUC's prior directions regarding the quantification of UFG, as well as UFG fluctuations and overall UFG volumes, noting that AUI's list of potential causes of UFG could be listed generically for any UFG application. The CCA therefore requested that the AUC direct AUI to document its efforts to reduce fluctuations, to allow parties to understand AUI's actual reduction efforts.

The AUC dismissed the CCA's request regarding the quantification of UFG, accepting AUI's argument that it was unable to further quantify causes of UFG. The AUC held that it was satisfied with AUI's explanations, and directed AUI to continue to quantify UFG where possible and to take appropriate actions to mitigate UFG.

With respect to AUI's efforts to mitigate overall UFG and UFG fluctuations, the AUC found that the slight decrease in UFG was encouraging, and expected AUI's UFG volumes to decrease in its next application. The AUC directed AUI, in its future UFG applications to:

(a) Continue to quantify the causes of UFG where possible, and explain any variances from prior years; and

(b) Continue to update its historical data set for UFG percentage losses or gains on a monthly basis.

The CCA submitted that AUI should be directed to examine the data sets that it uses for UFG as well as the time period for examining UFG, noting that the AUC first approved the May-to-June data set with a November 1st effective date over 25 years ago. The CCA submitted that it would be appropriate to re-examine the data collection period and effective date.

The AUC held that continuing the November 1st effective date and June to May data set continued to be appropriate, noting that negative UFG volumes at the start and end of the data collection period were low in relation to total UFG volumes and that changing the effective date would have no effect on the presence of month-to-month variances. The AUC therefore denied the CCA's request to change the UFG effective date and data collection period.

In light of the above determinations, the AUC approved the proposed decreases to Rider E UFG volumes to 1.31 percent, and Rider H UFG volumes to 1.31 percent, effective December 1, 2015.

Milner Power Inc and ATCO Power Ltd. Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology – Phase 2 Module B (Decision 790-D03-2015)
ISO Rule – Loss Factor and Loss Factor Methodology

This decision follows in a series of decisions regarding a complaint made by Milner Power Inc. ("Milner") on August 17, 2005 regarding Independent System Operator ("ISO") Rule 9.2: *Transmission Loss Factors* and Appendix 7: *Transmission Loss Factor Methodology and Assumptions* (collectively, the "Line Loss Rule"), which was implemented by the Alberta Electric System Operator ("AESO") on January 1, 2006.

On February 28, 2011, Proceeding 790, which is the subject of this decision, was bifurcated by the AUC to consider the following issues separately:

(a) Phase 1: Whether the AESO's Line Loss Rule contravened section 19 of the *Transmission Regulation*; and

(b) Phase 2: What remedy, if any, could be awarded to Milner in the event the AUC held in favour of Milner in Phase 1.

Phase 1 of Proceeding 790 is completed, with the AUC having upheld Milner's complaint, in Decision 2012-104 and Decision 2014-110, that the Line Loss Rule was unjust, unreasonable or unduly preferential, arbitrarily or unjustly discriminatory or inconsistent with or in contravention of the *Electric Utilities Act* (the "*EUA*") or the *Transmission Regulation* (the "*T-Reg*"). The AUC also found that the Line Loss Rule, as it exists today, does not support the fair efficient and openly competitive operation of the market.

<u>Background</u>

The AUC, in its previous decisions in Proceeding 790, provided a simplified explanation of how line losses are calculated on transmission lines. Losses are typically expressed through the equation $L = aP^2$, whereby a is a constant number, and P is the power flowing over a given power line. Therefore, the amount of losses on a line increases exponentially with the flow of power. As an example, the AUC noted that a line with a power flow of 100-megawatts would incur four times more losses than if that same line had a power flow of 50-megawatts. As a result of the relationship between distance, power flow and line losses, the proximity and size of a given generator to load customers plays a significant role in reducing or increasing line losses.

Under the *T-Reg*, the overall cost of transmission line losses is borne by generators, and the AESO is responsible for preparing line loss factors amongst generators to distribute the cost of losses. Some generators receive a credit for reducing losses, whereas others incur a charge for increasing losses, depending on their location and contribution to line losses on the transmission system.

<u>Allocation of Losses Amongst Generators</u>

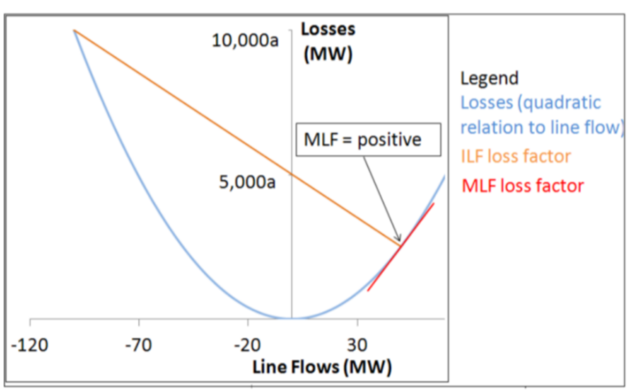
The issue at hand in this decision was how to properly allocate the loss charges and credits amongst the various generators in the province.

As a first step in determining the loss factor for each generator, the AESO is required to generate raw loss factors. The AUC described several methods that can be used to calculate loss factors.

<u>Raw Loss Factor Approaches</u>

A Marginal Loss Factor ("MLF") refers to the last loss caused by the last unit of power generated. Given the square relationship between line losses and power flow, losses increase at an increasing rate as more power is generated. As an example, the AUC noted that under the equation $L = aP^2$, if a generator is delivering 99-megawatts, it will create 9,801*a* of losses, whereas at 100-megawatts, it will create 10,000*a* of losses, and at 101-megawatts it creates 10,201*a*. Therefore, the marginal losses for the last increment of generation are around 200*a* at 100-megawatts, which the AUC noted was expressed by the formula MLF = $dL / dP = 2aP$.

However, the AUC noted that the scenario becomes more complex as more generators are added to a system. The AUC noted that if a generator connects next to a local load, and begins generating, total system losses will decline overall, but as the new generator approaches 100-megawatts of generation, the reduction of losses is reduced until it no longer has an impact on the amount of losses on the system with its last increment of generation. The AUC expressed the impact of the second generator's connection in the figure below:



The AUC noted that while MLF allows the measurement of the impact of the last unit produced (the red line in the figure), another methodology attributes losses by looking at the discrete impact before and after the new generator is connected (the yellow line in the figure). The AUC referred to this method as the Incremental Loss Factor ("ILF"). In the above example with the new generator connecting, the ILF looks to the losses on the system prior to the operation of the new generator, and the losses after the operation of the new generator.

The mathematical expression of ILF by the AUC was described as ILF = [$L(P) - L(0)$] / P, where $L(P)$ is the total losses calculated at the final output of the new generator, and $L(0)$ is the total losses associated with the generator before it generates anything. Using the figure, the new generator creates approximately 2,500*a* of losses at its final generation output, and the system losses prior to the operation of the generator are 10,000*a*. Therefore the net impact on losses for that generator is -7,500*a.*

The AUC explained that the Line Loss Rule, which was the subject of Milner's complaint, used a modified version of MLF. While the AUC described it as mathematically complex, it could be simplified as essentially an averaged snapshot of line losses from a generating unit during twelve periods throughout the year (high, mid, and low scenarios for each season), which is then divided by two. Therefore the AUC explained that in its simplest expression, the Line Loss Rule used what is called MLF/2. The resulting loss factor would be multiplied by the price and energy produced in each hour, and then summed for all energy produced in a year.

The AUC noted that losses generally take two forms:

(a) A generator's "own losses" created by losses in the form of heat resulting directly from the generator's own transmission of electricity; and

(b) "Aggregate system losses", either positive or negative, which result from that generator's power flows displacing and changing the power flows and consequential losses of other generators on the system.

In Decision 2014-110, the AUC found that the MLF/2 methodology did not calculate these raw loss factors in a manner that was compliant with the *T-Reg* or the *EUA*.

The AESO proposed a variant on the ILF methodology in this application. However, the AUC also noted that the proposed new Line Loss Rule filed by the AESO was not a filing contemplated under Section 25(7) of the *EUA*, noting that the AUC did not direct the AESO in respect of what a compliant Line Loss Rule should include. Therefore the AUC found that it was exercising its jurisdiction under

Section 25(6) of the *EUA* to specify what changes, if any, are required to make the Line Loss Rule compliant with the *EUA*. Therefore, the AUC did not consider the AESO's proposal to be the only method properly before the AUC, and held that proposals made by all parties would be entitled to a full consideration.

Two main approaches to calculating loss factors were put forward in the proceeding:

(a) The ILF methodology, proposed by the AESO and supported by a number of parties; and

(b) The Superposition methodology, proposed by ENMAX Energy Corporation ("ENMAX") and supported by TransAlta Corporation ("TransAlta").

ILF Methodology

The AESO described the ILF methodology as essentially a "but for" approach, calculating the difference between system losses with and without each generating unit by examining the changes to the system losses between the average level of net-to-grid generation from a specific generator, and reducing that generator's output to zero.

The AESO (and the parties supporting it) submitted that an ILF methodology gives effect to the requirement that the loss factor measures the impact of a generating unit on average system losses as it recognizes the full range of output, in contrast with the previous MLF/2, which only recognized the last increment of generation. The AESO also contended that the proposed methodology accounts for a generator's location as well, and satisfied all the legislative requirements for a Line Loss Rule.

While most parties supported the AESO's proposed Line Loss Rule, the AUC noted that a number of parties had concerns related to implementation, notably as it relates to the location at which the ILF is calculated, and various technical issues related to the AESO's choice of swingbus to rebalance the system once a generator is withdrawn in calculating raw loss factors.

Superposition Methodology

ENMAX, however, took serious issue that the only problems with ILF were related to implementation, and challenged the validity of the ILF approach as a whole. ENMAX submitted that the ILF methodology failed to accurately reflect how an actual power system works, and assumed a fundamental misallocation of losses. ENMAX instead proposed a Superposition loss factor methodology, based on a theorem of superposition. ENMAX summarized its proposal as reliant on the element voltages and currents from each applied source acting separately, essentially act together to form the algebraic sum of currents and voltages on the system. ENMAX likened its Superposition methodology as attempting to track the net flow of electrons from each generator to various points, to determine its contribution to system losses. TransAlta summarized the Superposition methodology as follows:

(a) Assess whether each generating unit's full injection is distributed by the system topology to serve loads;

(b) Assign a credit to a generating unit for reducing flow across a transmission element and assign a charge to a generating unit for increasing flow on a transmission element; and

(c) Aggregate the credits and charges to determine a generating unit's contribution to system losses, and divide this aggregate by the generating unit's injection to derive a raw loss factor.

ENMAX and TransAlta submitted that the Superposition methodology was superior since it could not assign a different loss factor to co-located units, while still recognizing the full range of a generator's output.

The City of Medicine Hat ("Medicine Hat") took issue with ENMAX's Superposition method, arguing that it did not calculate any incremental impacts of system losses, but rather attempts to deconstruct and assign power flows within a single operating state. Medicine Hat contended that the Superposition method was therefore not compliant, since the AUC held, in Decision 2014-110, that the contribution or impact of a generating unit was based on a change in system losses, therefore necessitating a base case and a change to the base case.

Milner Power Inc. ("Milner") and ATCO Power Ltd. ("ATCO") also took issue with the Superposition Method, notably that the allocation of losses to co-located generators was without economic justification and arbitrary, violating the principles of cost causation.

Ruling Whether the Methodologies Are Consistent with the Legislation

The AUC held that its concern at this stage of the proceeding was to determine whether any (or neither) of the proposed Line Loss Rule methodologies complied with the existing legislation. The AUC held that if it could be determined that a methodology did not comply, even on a single ground, that could not be remedied, it would be removed from further consideration.

The AUC determined that the ILF methodology was reasonably capable of producing a Line Loss Rule and of calculating line loss factors that were not unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory, nor inconsistent with the applicable legislation. The AUC found that this was due to the fact that ILF by definition provides a given generating unit's impact across the full range of its output. The AUC also found that ILF calculated loss factors that were representative of the impact on the average system losses of each generating facility relative to load since it measured the difference in losses with and without each generating facility.

The AUC further held that the Superposition method failed to comply with the legislation and was incapable of being remedied to comply with those requirements. The AUC provided the following reasons, among others, for making the above finding. The Superposition methodology:

(a) Failed to recognize a generator's contribution to line losses across the full range of the facility's output, since the Superposition method did not compare the impact on losses between a base case and a second scenario, but rather only the base case condition; and

(b) Did not allocate losses to the generating unit causing them, as it allocated losses equally to facilities injecting power onto the same transmission element. The AUC determined that this would inevitably result in the socialization of line losses, thereby violating the principles of cost causation.

Location

Under the AESO's proposed filing, the "location" of a unit was considered to be its metering point identifier. This approach, according to the AESO, would provide identical loss factors to co-located units that are operated in the same manner, while allowing differently sized or operated units to be assigned different loss factors. The AESO submitted that this would remove the potential for discrimination between closely located generators with different impacts on system losses.

The AUC directed the AESO to make changes to the Line Loss Rule to specify that the location of a "generating facility" as defined in the *EUA*, be the location of each metering point identifier for a generating unit or group of generating units. This determination, according to the AUC would allow for generators that own or control generating facilities to aggregate or disaggregate their generating facilities as they choose, and at their own expense.

Such aggregations, or disaggregations, in the AUC's determination, would allow market participants to contract for as many or as few metering point identifiers as they wish. However, any units that are aggregated must also offer into the energy market as a single source asset through one set of price/quantity pairs. The AUC further requested comments from the AESO in its compliance filing regarding how the ability to aggregate or disaggregate would apply to units subject to a power purchase arrangement.

Swingbus and Base Cases for ILF Analysis

The AUC noted that the principal advantage of the ILF method is that it applies a "but-for" approach, examining the full range of a generating unit's output. However, a shortcoming of this approach is that the power system must be "rebalanced" through a swingbus to account for the removal or addition of the generating unit. The AUC noted there are two ways of rebalancing a power system:

(a) Scaling down load; or

(b) Scaling up generation to replace the output of the removed generating unit.

The AESO, in scaling up generation has two further options of hypothetically re-dispatching generation:

(a) Rely on the generic stacking order to rebalance the system; or

(b) Rely on the energy market merit order to rebalance the system.

Parties supporting the ILF methodology generally favoured the load scaling method over re-dispatching through the generic stacking order, relying on previous findings by the AUC in Decision 2014-110 that load scaling was "not inconsistent" with the *T-Reg*. The AESO however, offered its reasoning that reducing loads proportionally across the system removed any subjectivity in selecting the necessary adjustments following the removal of the generating unit.

Milner's reasons favouring load scaling was appropriate since the *T-Reg* required that load not pay directly for losses.

With respect to re-dispatch through the generic stacking order, the AUC determined that the witness testimony provided during the oral portion of the hearing made clear that the generic stacking order was never intended to reflect which generating facility would be dispatched next in a system rebalancing scenario. The AESO opposed the use of the generic stacking order on the basis that re-dispatch under the generic stacking order is dependent on the relative location of the generating unit being removed, and the unit being re-dispatched. The AESO also opposed the use of the generic stacking order, since it is a forecast based on a historical analysis of losses on the system, and is therefore subjective.

The AUC held that losses cannot be determined in a vacuum, as they depend on a number of factors on the system in real-time. The AUC held that scaling load down to rebalance the system introduced a conceptual problem in that what is measured it not what actually occurs on the system when a generator is removed. In reality, the AUC found that the AESO would dispatch other sources of generation to take up the lost generation when a generator is removed from service (such as during an unforeseen maintenance event.) Therefore, the AUC held that it would be reasonable to expect the "but-for" analysis to examine the system at a constant load, and thereafter model the total line losses by dispatching other generating facilities to match the load. The AUC also held that scaling down load would be an abnormal operating condition under section 31(2) of the *T-Reg*, since the AESO very rarely, if ever, curtails load on the system in day-to-day operation. However the AUC stopped short of finding that load re-balancing would violate the *T-Reg*, since the entire exercise is entirely hypothetical.

The AUC therefore determined that the full load on the system is required for rebalancing, rather than scaling down load. The AUC considered that dispatching up using the merit order more closely reflects what would occur in reality if a generating unit were to suddenly go offline. Therefore, the AUC held that re-balancing the system through merit order dispatch would be the most practical.

The AUC further held that the AESO has the merit order readily available, since it is compiled 8,760 times each year (one for each hour), and should therefore be used as a base case for the calculation of loss factors. Additional reasons were provided by the AUC for directing that the AESO use 8,760 base cases. Among these reasons were:

(a) A larger number of base cases instills greater confidence in forecast loss factors;

(b) Application of the merit order will reduce the necessity of manual interventions by the AESO in developing loss factors;

(c) The merit order is a transparent and publicly available record for the prior year;

(d) Using 8,760 merit orders allows the AESO to use a simple average of raw loss factors rather than a weighted average, which can then be clipped and shifted to within the appropriate collars.

The AUC recognized the potential administrative ramifications of moving from 12 base cases to 8,760 base cases, and therefore requested the following information from the AESO prior to making its compliance filing for the Line Loss Rule:

(a) The operational ramifications for developing 8,760 base cases, including labour, equipment and processing timeframes and costs;

(b) Whether a different number of bases cases would provide the same potential accuracy as 8,760 base cases, and any potential savings associated with such a lower number; and

(c) An estimate of when a new Line Loss Rule could be ready for implementation.

<u>General Issues</u>

The AUC noted that the ILF method inherently leads to a global over-recovery of losses, requiring a shift factor to be applied to each generator to compensate for the over-recovery. The AESO proposed to make such adjustments at each step to offset the risk of an anomalous raw loss factor materially affecting the final loss factor. ATCO proposed as an alternative that the AESO's proposal be simplified to applying a volume weighted average thereby obviating the need for multiple rounds of adjustments.

However, the AUC held that its prior determination on the use of the merit order to calculate 8,760 base cases (one for each hour in a year), would result in it not being necessary or desirable to adjust raw loss factors at each base case, and noted that it expected the AESO to address this issue in its compliance filing.

The Line Loss Rule further applies "collars" to the loss factors that fall outside of the limits prescribed by section 31(2)(f) of the *T-Reg* and charges two times the system average, and credits one times the system average. The AESO proposed to clip and shift the loss factors repeatedly until all loss factors for generating units outside the collars fall within the required limits, as this would be simpler than applying linear compression to all generating units.

The AUC held that the AESO's proposal was acceptable, finding that it satisfied the requirements of the *T-Reg* to use a common method to fit loss factors within the collars.

<u>Order to the AESO</u>

The AUC therefore directed the AESO to file a plan to implement the AUC's findings in this decision, by February 1, 2016. The AUC directed that this filing by the AESO include a plan to develop a revised Line Loss Rule for approval. The AUC noted that once the plan is reviewed and approved, it would direct the AESO to submit the Line Loss Rule as a compliance filing for review and approval on a date to be determined.

In setting a potential effective date, a number of parties urged the AUC to set as early an effective date as possible, noting that the current unlawful Line Loss Rule has been in effect since January 1, 2006. However, the AUC held that it was constrained in setting an effective date by Section 25(9) of the *EUA*, which states that the earliest date a rule may become effective is the day on which the AESO files a revised rule.

The AUC also noted that the changes it directed were significant, and would likely require several internal changes for processing and information by the AESO. As a result, the AUC noted that these changes may take time, and that other unanticipated implementation issues may arise.

The AESO expressed some concern about its need to comply with Section 31(2) of the *T-Reg*, which requires loss factors to apply for a period of at least one year, but not more than five. The AESO's concern arose from its capability to implement a rule prior to January 1, 2016. The AUC noted that the AESO had several options at its disposal, such as lengthening the time that the 2015 loss factors are in place.

The AUC cautioned that its findings on the effective date for the new Line Loss Rule had no effect on its parallel authority under Sections 119(4) and 121 of the *EUA*, to adjust line loss charges from January 1, 2006 to the new effective date, and its authority to determine final line loss charges in Module C of this proceeding up to the effective date of the new loss factors.

AltaLink Management Ltd. Transmission Line 423L (Decision 3450-D01-2015)
Transmission Line – Rule 007

AltaLink Management Ltd. ("AltaLink") applied to the AUC to construct and operate a new transmission line, to be designated as 423L approximately 16 kilometers in length and located east of Lacombe, Alberta (the "Application"). The Application comprised of the following components:

(a) Construction of a single-circuit 138-kilovolt (kV) transmission line to be designated as 423L, from the existing Lacombe 212S substation to the existing Ellis 332S substation;

(b) Alteration of transmission line 80AL near the Lacombe 212S substation to accommodate the 423L transmission line;

(c) Alteration of transmission line 784L near the Ellis 332S substation by relocating the line onto double-circuit structures with transmission line 423L for one quarter section;

(d) Alteration of Lacombe 212S substation by adding two new 138-kV circuit breakers;

(e) Alteration of Ellis 332S substation by adding one 138-kB circuit breaker; and

(f) The salvage of portions of transmission lines 80AL and 784L to accommodate transmission line 423L,

(collectively, the "Project").

AltaLink submitted several route options in response to concerns raised during its consultations for the Project.

The AUC considered the following issues related to AltaLink's application:

(a) Was the application consistent with the need for transmission facilities approved in Decision 2012-098?

(b) Did AltaLink's application comply with the requirements of the Rule 007: *Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations* ("*Rule 007*")?

(c) How should the AUC treat the evidence with respect to the full rail parallel route?

(d) Would the approval of the application be in the public interest pursuant to section 17 of the *Alberta Utilities Commission Act*?

<u>Need</u>

The needs identification document for the project from the Alberta Electric System Operator ("AESO") was previously approved by the AUC in Decision 2012-098. The AUC also approved facilities in Decision 2014-219 to meet a portion of the need identified in Decision 2012-098.

The AUC held that no party questioned whether AltaLink's application to construct and operate the Project met the need identified by the AESO. Therefore the AUC found that the Project was consistent with and met the need approved in Decision 2012-098.

<u>Consultation</u>

The AUC noted that *Rule 007* requires applications for transmission line projects to conduct a participant involvement program before an application is filed. The applicant is expected to ensure that the information is understandable, and that the project is discussed with the widest possibly impacted audience as early as practicable.

The AUC found that AltaLink's participant involvement program met the requirements of *Rule 007*, allowing interveners to understand the Project, and allowing them to meaningfully convey their concerns with the Project. The AUC determined that AltaLink had provided the means for stakeholders to make further inquiries, and express their concerns. The AUC also found that AltaLink's alternate route selections were developed as a result of consultations with stakeholders, and demonstrated how stakeholders' views were incorporated into the applied-for routes.

The AUC noted that effective consultation programs may not resolve all stakeholders' concerns, and that parties may not agree on the impacts of a proposed project. The AUC characterized the process of consultation as a two-way street, holding that affected parties need to articulate the impacts they feel they may face, in order to allow the proponent to respond to, and incorporate those concerns.

<u>Environmental Impacts</u>

AltaLink submitted that in assessing the potential environmental impacts of the Project, it implemented a staged approach to integrate environmental considerations into the Project's development, design and construction. AltaLink submitted that the environmental setting of the Project included terrain, soils, vegetation, hydrogeology, wetlands, watercourses, and wildlife. AltaLink submitted that it performed a number of studies including:

(a) A wetland evaluation report;

(b) Early and late season vegetation survey reports;

(c) Weed survey reports; and

(d) Wildlife survey reports.

AltaLink noted that these reports described a number of recommended mitigation measures that it planned to apply to the Project. Among the mitigation measures AltaLink planned to implement were:

(a) A requirement to develop a construction environmental management plan prior to the start of construction;

(b) A requirement to develop a post-construction reclamation plan, including:

 (i) Re-contouring of disturbed areas;

 (ii) Erosion and settlement control methods;

 (iii) Topsoil salvage and replacement; and

 (iv) Re-vegetation;

(c) Long term monitoring during operation of the Project, including avian protection measures such as installing bird markers and flight diverters; and

(d) Implementing standard procedures for vegetation management, waste handling and disposal plans.

AltaLink submitted that each of the route options were viable from an environmental impact perspective, and that no one route was strongly favoured for its environmental impacts.

The AUC held that the Project would be constructed on road allowances and that the lands surrounding it are primarily agricultural. The AUC held that the potential environmental impacts would be limited and, with appropriate mitigation measures, each of the route options presented were satisfactory from an environmental perspective.

<u>Noise</u>

AltaLink did not provide a noise impact assessment, as it submitted that no continuous audible noise sources were proposed as part of the Project.

The AUC accepted AltaLink's submissions, noting that no noise emitting components were being added to any of the substations within the Project.

<u>Electrical Effects on Canadian Pacific Railway Ltd. ("CP Rail")</u>

AltaLink submitted a report conducted by CP Rail regarding electromagnetic compatibility of the CP Rail line and the Project. The report, prepared by CP Rail determined that electromagnetic interference with the CP Rail line would occur if the Project were constructed over the preferred route, alternate route, and the full rail parallel route. However, CP Rail's report also noted that the preferred and alternate route would be acceptable if mitigation measures were implemented.

CP Rail's report stated that the preferred mitigation measure was to increase the distance of the Project from the rails. However, should a larger setback distance not be possible, CP Rail's report stated that the only acceptable mitigation method was to install insulated joints along the line.

Other parties attacked the CP Rail report on the basis that CP Rail had omitted any analysis of rail tracks on the north and south ends of the Project, and further failed to include an analysis of conductivity or soil resistivity in its model. Other landowners submitted that CP Rail failed to consider any alternative mitigation measures, such as direct grounding of the rails to the soil.

AltaLink replied by stating that CP Rail intentionally used a discontinuity in its model at the south end of the Project as CP Rail did not own that track, and was not prepared to accept or allow any unnecessary risk to another owner's track. CP Rail also used a discontinuity along the north end of the Project as it was not prepared to accept any risk for any portion of its track outside the footprint of the Project. AltaLink also responded that CP Rail did not consider direct grounding due to the fact that such measures would unduly interfere with signalling and existing active crossings along the rails.

The AUC held that the modelling in the CP Rail report was reasonable, including the assumptions used by CP Rail. The AUC further determined that the CP Rail report was sufficient to demonstrate that CP Rail would experience electromagnetic interference due to a parallel transmission line along its tracks, and noted that if the preferred route, alternate route or full rail parallel route were approved, some level of mitigation would be required.

The AUC made no finding on the appropriateness of the mitigation measures to be used, noting that the modelling of impacts in the CP Rail report would be verified against actual measurements should any of the routes be approved and constructed.

Route Alternatives

AltaLink had previously applied to construct and operate the Project providing evidence and reply evidence regarding its preferred route and alternate route, which had previously paralleled rail lines owned by CP Rail. AltaLink later withdrew the alternate route as a result of ongoing discussions with CP Rail. AltaLink withdrew the alternate route due to questions regarding its ability to parallel the railway for the southern portion of the alternate route. As a result, AltaLink's application did not include an option to fully parallel the CP Rail line along the alternate route, as AltaLink submitted that it may cause undue risk to CP Rail's operations or may cause electromagnetic interference to CP Rail's operations.

As a result of the changes to AltaLink's alternate route due to concerns from CP Rail, several landowner interveners requested that the AUC strike AltaLink's evidence related to the withdrawn alternate route, or to compel CP Rail to attend the hearing and provide evidence of its own. For reasons set out within the rest of the decision, the AUC determined that it was not necessary to strike any portion, or to compel evidence, as AltaLink's witness panel included a CP Rail employee.

Several interveners requested that the AUC deny the application as filed and to direct AltaLink to re-file its application for the Project to be routed along the full rail parallel route They submitted that the viability of the full rail parallel route indicated that the applied for routes were not in the public interest.

AltaLink submitted however, that the AUC was required to separate its consideration of the application from the possible mitigation measures required, arguing that the AUC lacked the jurisdiction to direct CP Rail to impose any particular mitigation measures to accommodate the full rail parallel route.

The AUC held that the *Hydro and Electric Energy Act* (the "*HEEA*") permitted it to order changes to the location of a transmission line; prescribe the location and route of the transmission line as precisely it considers suitable; and prescribe the location of the right-of-way and the relationship of its boundaries to the transmission line or any part of it. However, since AltaLink did not apply for the full rail parallel route, the AUC held that it could not approve that route in its decision.

In answering the question related to its jurisdiction, the AUC held that the onus was on the applicant to demonstrate that it's applied for route stands out as the superior route. If it did find that the Project was not in the public interest, it could have denied the application and directed AltaLink to apply for the Project in a specific location, including the full rail parallel route.

However, the AUC determined that it did have sufficient evidence before it to make a meaningful comparison between the full rail parallel route and the applied for routes. Therefore, the AUC held that if it were to determine that the full rail parallel route was a superior alternative, it may exercise its discretion under section 19 of the *HEEA* and deny the application and direct AltaLink to apply for the full rail parallel route.

With respect to the admissibility of expert witness testimony and evidence, the AUC maintained its current practice of not having to qualify experts beforehand. The AUC held that each of the witnesses that presented evidence in a fair and objective manner, consistent with their expertise, was considered an expert. The AUC did however classify some witnesses who were presented as expert witnesses as witnesses providing "technical evidence" instead. The AUC described technical evidence as evidence that is expert evidence provided by a corporate witness, and involves an additional step where the AUC considers whether, or to what degree, the policy evidence, factual evidence or technical evidence, was influenced by the witness' position as an employee or representative of the party.

AltaLink submitted that it identified its preferred route based on a combination of factors, including conversations with stakeholders, environmental assessment impacts, number of corner structures required for construction, accessibility for maintenance purposes, and electrical considerations. AltaLink's preferred route, in its submission, had lower residential impacts than the alternate routes, as it would avoid a number of residences that would otherwise fall within 150 metres of the Project.

Several landowners promoted the landowner suggested route, which avoided two additional residences, and would further avoid AltaLink having to replace a distribution line owned by EQUS REA Ltd. In response, AltaLink accepted the landowner suggested route option, submitting that the combined preferred route with the landowner suggested route would have the lowest overall residential impact, with no residences within 150 metres of the Project.

The AUC held that while all of the applied for routes were viable, the applied-for preferred route, together with the landowner suggested route option was the superior route for the Project, and approved that route. The AUC determined that the agricultural impacts of the preferred route could be mitigated by AltaLink's proposed removal of two structures along the preferred route.

The AUC specifically determined that the landowner suggested route option was superior to the preferred route along the southern portion of the Project due to the lower residential and visual impacts compared with the preferred route. The AUC also found that the incremental costs of this route alternative were outweighed by the benefits to landowners, and not having to relocate other local distribution lines.

The AUC rejected the alternate route and the full rail parallel route, noting that the number of residences and landowners impacted would be drastically higher than the approved route, particularly along the northern section of the Project.

Decision

Accordingly, the AUC found that the Application met the requirements of *Rule 007*, and was in the public interest. The AUC therefore granted AltaLink approval to construct the Project along the preferred route with the landowner suggested route option.

NATIONAL ENERGY BOARD

Stolt LNGaz Inc. Licence to Export Gas as Liquefied Natural Gas (November 5, 2015 Reasons for Decision)
Export Licence - LNG

Stolt LNGaz Inc. ("Stolt") applied to the NEB pursuant to section 117 of the *National Energy Board Act* (the "*NEB Act*"), for a licence to export gas in the form of liquefied natural gas ("LNG"). Stolt sought the following terms in its LNG export licence application:

(a) A 25 year licence term starting on the date of first export;

(b) An included 15 percent annual tolerance, and a maximum annual export quantity of 0.835 billion cubic meters or 29.47 billion cubic feet (Bcf);

(c) A maximum term quantity of 20.875 billion cubic meters or 736.75 Bcf over the term of the licence;

(d) A point of export located at the outlet of the loading arm of the proposed natural gas liquefaction terminal to be located in the vicinity of Bécancour, Québec; and

(e) An early expiration clause whereby the licence would expire ten years from the date of approval by the Governor in Council issuing the licence if exports have not commenced (the "Application").

Stolt submitted that the quantity of LNG it sought to export did not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, as required by section 118 of the *NEB Act*. Stolt, in support of its application, filed two reports which it submitted demonstrated that the Canadian resource base remains large enough to meet Canadian gas needs and remains robust. Stolt also submitted that there has been a major increase in estimates of Canada's tight gas and shale gas resources recently, and that it was reasonable to extrapolate such an outlook into the future based on technological advancements in drilling and completion techniques.

Stolt stated that the North American gas market was highly liquid, open, efficient, integrated and was responsive to changes in supply and demand. Stolt noted that a 20 percent increase to Canadian demand for natural gas would not negatively affect domestic supplies or proposed export volumes.

The NEB approved the Application subject to the approval of the Governor in Council, on the terms proposed by Stolt. The NEB determined that the volume of LNG that Stolt proposed to export did not exceed the surplus remaining, after due allowance had been made for the reasonably foreseeable requirements for use in Canada, having regard to trends in the discovery of gas in Canada. The NEB noted that the evidence in the Application was generally consistent with the market monitoring information maintained by the NEB itself.

While the NEB noted that while the aggregate volume of LNG licences granted recently represent a significant volume for export from Canada, the proposed LNG ventures were each competing for a limited global market and face numerous challenges. Accordingly, the NEB found that Stolt's LNG export assumptions, whereby not all LNG volumes for export would materialize, was reasonable.

Pembina NGL Corporation and Pembina Resource Services Canada and Pembina Infrastructure and Logistics LP Application for a Licence to Export Propane (November 5, 2015 Reasons for Decision)
Licence to Export - Propane

Pembina NGL Corporation and Pembina Resource Services Canada, by its managing partner 1195714 Alberta Ltd., and Pembina Infrastructure and Logistics LP by its managing partner 1598313 Alberta Ltd. (collectively, "Pembina") applied to the NEB pursuant to section 117 of the *National Energy Board Act* (the "*NEB Act*"), for a licence to export propane (the "Licence"). Pembina sought the following terms in its application to export propane:

(a) A 25 year licence term starting on the date of first export;

(b) An included 15 percent annual tolerance, and a maximum annual export quantity of 5,003,420 m^3 or 31,471,511 barrels;

(c) A maximum term quantity of 125,085,500 m^3 or 786,762,775 barrels over the term of the licence;

(d) A point of export located at either:

  (i) A marine export terminal on the west coast of Canada; or

  (ii) Points along the Canada-United States border at railway crossings (specifically at Coutts, Alberta, Kingsgate, British Columbia, Huntington, British Columbia, and White Rock, British Columbia), and

(e) An early expiration clause whereby the licence would expire ten years from the date of approval by the Governor in Council issuing the licence if exports have not commenced.

The NEB agreed with Pembina, holding that the exports did not exceed the surplus remaining after due allowance has been made for the reasonable foreseeable requirements for use in Canada as required by section 118 of the *NEB Act*. While the NEB found that the estimates of recoverable propane were generally less reliable than for natural gas, the NEB also agreed with Pembina that a resource assessment for propane would have required a significant amount of work to complete, and was not likely to vary significantly from present estimates. The Board also held that the estimates provided in the application were generally consistent with the NEB's own monitoring effects. However, the NEB did note that it would have been much better served if such information was available to it in making a surplus determination under section 118 of the *NEB Act*.

The NEB determined that the evidence before it demonstrated that propane resources were well above any plausible demand scenario given the high supply situation for propane, and that the proposed exports were considered small in the context of the North American market.

The NEB therefore granted the export licence to Pembina as applied for.

Inspection Officer Order DRA-1-2015 to NOVA Gas Transmission Limited pursuant to section 51.1 of the National Energy Board Act
Non-compliance – Inspection Officer Order

The NEB issued Inspection Officer Order DRA-1-2015 (the "Order") to NOVA Gas Transmission Limited ("NGTL") in relation to an excavation at the NPS 20 McDermott Extension Athabasca River Horizontal Directional Drill crossing (the "Site").

The Order states that NGTL reported four incidents at the Site related to drilling fluid releases into the Athabasca River. The releases occurred on October 23, 2015 and November 1, 7, and 9, 2015. The Order notes that NGTL ceased drilling operations on November 9, 2015. After reviewing the Material Safety Data Sheets, the NEB Inspection Officer found that the toxicity of the drilling fluid could not be clearly established.

As a result, the Inspection Officer determined that NGTL was non-compliant with Section 48 of the *Onshore Pipeline Regulations*, as well as Condition 3 of Order XG-N081-2015 and Section 7.1 of the Environmental Protection Plan for the Site.

The Order specifies that NGTL must take measures to:

(a) Cease drilling operations at the Site;

(b) Provide for the approval of the Inspection Officer, a continuance plan, which includes:

(i) Drilling fluid composition information;

(ii) Specific concentrations of additives used in the drilling fluid mixture; and

(iii) An integrated contingency plan for fluid releases into the Athabasca River for frozen and non-frozen conditions.

Transparency of National Energy Board Compliance Verification Activities Update
Inspections Reports - Transparency

The NEB announced, by way of letter addressed to all companies under the jurisdiction of the NEB, that it would begin posting Inspection Reports for NEB-regulated facilities onto its website for inspections that have occurred since September 28, 2015. The Inspection Reports that will be released onto the NEB website will include:

(a) Safety Inspection Reports;

(b) Environmental Protection Inspection Reports;

(c) Integrity Management Inspection Reports; and

(d) Damage Prevention Inspection Reports.

The following reports would not be made publicly available:

(a) Security Inspection Reports; and

(b) Inspection Reports under the Canada Labour Code.

The NEB stated that the publication of reports onto the NEB website would conform to the following process, which it anticipates will take approximately six weeks:

(a) Once completed, the NEB Inspection Officer will send a draft to the company;

(b) The company will have five (5) days to review the draft Inspection Report and provide feedback on factual, technical and personal information matters;

(c) The NEB will review the feedback and revise the Inspection Report as it deems necessary, and redact information that cannot be disclosed; and

(d) The NEB will post the Inspection Report on the NEB's website in both official languages.

Copies of the Inspection Reports posted by the NEB, going back to September 28, 2015 can be accessed here.

Cedar 1 LNG Export Ltd. Application for a Licence to Export Natural Gas as Liquefied Natural Gas (November 26, 2015 Reasons for Decision)
Export Licence - LNG

Cedar 1 LNG Export Ltd. ("Cedar") applied to the NEB pursuant to section 117 of the *National Energy Board Act* (the "*NEB Act*") for a licence to export natural gas in the form of liquefied natural gas ("LNG") on the following terms:

(a) A licence term of 25 years;

(b) A maximum annual export quantity of 8.55 billion cubic metres, or 302 billion cubic feet of LNG, including 15 percent annual tolerance;

(c) A maximum term quantity of 214.10 billion cubic meters, or 7,558 billion cubic feet;

(d) An export point located at the outlet of the loading arm of the liquefaction terminals which Cedar anticipates to be located in the Northern Douglas Channel, near Kitimat, British Columbia; and

(e) An expiration clause where the licence will expire ten years after approval from the Governor-in-Council if LNG exports have not commenced on or before that date,

(collectively the "Licence").

In support of the applications the Cedar applicants submitted two studies to demonstrate that the quantity of gas to be exported does not exceed the surplus remaining after the due allowance has been made for the reasonable foreseeable requirements for use in Canada:

(a) The Long-Term Natural Gas Supply and Demand Forecast to 2050 – prepared by Ziff Energy ("Ziff Report"); and

(b) A Description of the Implications on the ability of Canadians to meet their natural gas requirements and an Assessment of whether this gas is surplus to reasonable foreseeable requirements for use in Canada – prepared by Roland Priddle ("Priddle Report").

The Ziff Report stated that Canadian and North American resource bases were robust and continue to grow. The Ziff Report also stated that there was an abundance of low-cost natural gas due to shale gas and unconventional gas plays, and expected the markets to function efficiently throughout its forecast period. The Ziff Report conducted a sensitivity test by increasing forecasted demand by 20 percent, and noted that the incremental increases were not material to its conclusions in respect of the surplus of gas available.

The Priddle Report concluded that the Canadian gas markets have and will likely continue to be adequately supplied, and that such a trend would continue under an integrated gas market, which was characterized as highly liquid, open, and efficient. The Priddle Report also concluded that the abundant volume of natural gas would help support an assessment that the quantities of natural gas to be exported by Cedar would not threaten the ability of the market to meet Canadian requirements for natural gas.

The NEB decided to issue the Licence to Cedar at the proposed export point, subject to the approval of the Governor in Council and subject to the terms and conditions as requested by Cedar. The NEB held that it was satisfied Cedar had demonstrated that the gas resource base in Canada could reasonably accommodate foreseeable Canadian demand, including the LNG exports proposed by Cedar.

As part of the conditions of the Licence, the NEB approved a 15 percent annual tolerance, noting that the maximum term quantity of the Licence is inclusive of the 15 percent tolerance amount. The NEB also accepted the request for a sunset clause of 10 years in length, noting it to be generally consistent with NEB practice.