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REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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ALBERTA COURT OF APPEAL

***Alberta (Utilities Consumer Advocate) v. FortisAlberta Inc.*, 2016 ABCA 333 (October 28, 2016)**
Performance Based Regulation – Asset Disposition – Timing of Rate Base Adjustments – Leave to Appeal Denied

AUC PBR Asset Disposition Decision

Fortis Alberta Inc. ("Fortis") acquired land (the "Land") and contemplated using it for construction of a centralized inventory facility. However, upon review, Fortis determined a decentralized inventory model would be more efficient and therefore no longer needed the Land. Fortis applied to the AUC requesting approval to sell the Land.

In its decision consenting to Fortis' disposition of the Land (the "AUC Decision"), the AUC also held the Land could remain in the rate base until the next rate base adjustment in 2017, in accordance with Fortis' Performance Based Regulation ("PBR") plan.

In the AUC Decision, the AUC noted that during an applicable PBR term, "the starting rate base reflected in the going in rates is not adjusted to keep track of actual events except in extraordinary circumstances." The AUC held that no such extraordinary circumstances existed in this case to warrant adjustment of the rate base earlier than prescribed under Fortis' PBR plan.

The Appeal

The Utilities Consumer Advocate ("UCA") appealed to the ABCA under section 29(1) of the *Alberta Utilities Commission Act* (the "*AUCA*"), on the grounds that the AUC erred in its determination of the date the Land must be removed from the rate base (the "Removal Date").

The UCA submitted that the Removal Date is the date the Land could no longer be considered used or useful, and that the AUC did not have the discretion to permit an asset to remain in the rate base any longer. The UCA submitted that the Removal Date should be in 2011, when Fortis completed construction of a different facility on nearby land.

In its decision, the ABCA denied the UCA leave to appeal (the "ABCA Decision").

Leave to Appeal under *AUCA* Section 29(1)

AUCA section 29(1) provides for an appeal from the AUC to the ABCA on questions of law or jurisdiction only.

The ABCA listed the following factors it considers on such an appeal application:

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

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

c) whether the appeal is prima facie meritorious;

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

e) the standard of appellate review that would be applied should leave be granted.

The ABCA first considered the applicable standard of appellate review of the AUC Decision, should leave be granted.

The Court noted that a question involving the AUC's ratemaking authority, goes to the core of its mandate and expertise, and that the applicable standard of review is reasonableness. This finding requires a high threshold be met for leave to be granted.

Parties' Submissions re Asset Removal from Rate Base

The UCA submitted that:

a) an asset must <u>always</u> be removed from the rate base as soon as it is no longer used or required to be used by the utility; and

b) therefore, the AUC was unreasonable in its determination of a Removal Date after the Land was no longer an asset required to be used to provide utility services.

Fortis distinguished the authorities relied on by the UCA regarding cost of service regulated entities, noting that Fortis is a utility subject to a PBR Plan, which, the ABCA agreed, "severs the link between Fortis' rates and the rate base itself."

ABCA Decision

The ABCA rejected the UCA's argument, and held that the AUC did not unreasonably exercise its discretion in allowing the value of the Land to remain in the rate base until the next re-basing, pursuant to Fortis' PBR plan.

The ABCA held that the question as to whether something was "extraordinary circumstances" was not a question of law or jurisdiction and fell squarely within the core of the AUC's mandate, and therefore, dismissed the UCA's application.

***Coulas v. Ferus Natural Gas Fuels Inc.*, 2016 ABCA 332 (October 31, 2016)**
Natural Gas Facilities – Appeal of AER Decision Denying Request for Regulatory Appeal – Leave to Appeal Granted

In *Coulas v. Ferus Natural Gas Fuels Inc.*, 2016 ABCA 332 (the "ABCA Decision"), the ABCA considered Silvia Coulas' application for leave to appeal an AER decision (the "AER Decision"). The AER Decision denied Coulas' application for a regulatory appeal of the liquid natural gas ("LNG") facility licence the AER issued to Ferus Natural Gas ("Ferus").

The ABCA granted Ms. Coulas leave to appeal for the reasons summarized below.

Background

The ABCA summarized the relevant factual background, noting that in 2015, the AER advised Ferus that it had jurisdiction over the its LNG facility (the "Facility") and that Ferus must apply for a licence to operate. Ferus made that application in December 2015 (the "Application"). The Application did not request any additions or modifications to the existing Facility.

Ferus did not provide Ms. Coulas with personal notice of the Application, as directed by the AER.

The ABCA noted that there was no dispute between the parties that Ms. Coulas did not view the public notice, but found out about the Application after the AER issued the licence on January 19, 2016, without a hearing.

Coulas Leave Application

Ms. Coulas applied for leave to appeal on the grounds that the AER erred in law by:

a) finding that the applicant was not an "eligible person" who was "directly and adversely affected";

b) improperly interpreting its legislative scheme in finding that

   (i) the issuance of the licence was "an administrative decision", thereby breaching the rules of natural justice;

   (ii) the Application ... "complied with all requirements under the regulations" when the evidence showed otherwise;

c) finding that the applicant's concerns were addressed and determined by the County; and thereby breached its duty to not improperly delegate authority; and

d) failing to provide adequate reasons for its refusal of the regulatory appeal request.

AER Decision Dismissing Request for Regulatory Appeal

The ABCA summarized some of the AER findings subject to appeal, including:

a) the issuance of the licence was an "administrative decision" as it did not result in any new construction, expansion, or change to the Facility;

b) the licencing was merely an application to meet the new AER approval requirements for processing facilities under the *Oil and Gas Conservation Act*;

c) the Facility complied with the AER regulatory requirements (including the *Noise Directives*);

d) there were no adverse effects as a result of the licencing and therefore "Ms Coulas had not demonstrated that she is directly and adversely affected"; and

e) Ms Coulas had attended the County meeting in 2013 when the Ferus Facility was discussed prior to its construction, voiced her concerns and Ferus had responded to those concerns at that time.

AER/Ferus Submissions

The AER submitted that a deferential standard of review should apply, given the AER's knowledge and expertise about the oil and gas industry and that the AER was interpreting its own legislation, regulations, and rules.

The AER submitted that the question as to whether Ms. Coulas is a person "directly and adversely affected" is a question of fact or mixed fact and law, to which no appeal lies to the ABCA under the *Responsible Energy Development Act* ("*REDA*").

The ABCA Decision Granting Leave to Appeal

The ABCA held that Ms Coulas raised a serious and important issue that the AER may have acted unreasonably or unlawfully in issuing the licence to Ferus without holding a hearing. Specifically, the ABCA held the AER may have erred in law in finding that the level of interest of a landowner and resident within 1.5km of an operational facility was insufficient to make such an applicant "directly and adversely affected" by the licencing decision made without a hearing.

The ABCA granted leave to appeal on the questions of:

a) whether the AER erred in law in determining that the applicant was not an "eligible person" under the *REDA*; and

b) whether it was an error of law for the AER to conclude that the issuance of the Facility licence was merely an "administrative" decision.

The ABCA also granted leave to appeal on natural justice grounds, stating:

> … it is arguable that there may be a significant natural justice flaw in a procedure that would grant the licence, and deny an appeal of same, without notice or affording a full hearing on either issue, particularly considering this applicant lives in very close proximity to the Ferus Facility …

The ABCA denied leave to appeal on the other grounds of appeal, noting that many of the issues raised on those grounds were subsumed into the natural justice and interpretation grounds of appeal for which the Court did grant leave.

ALBERTA COURT OF QUEEN'S BENCH

***Fort Chipewyan Métis Nation of Alberta, Local 125 v. Alberta (Minister of Aboriginal Relations*)**, **2016 ABQB 713 (December 15, 2016)**
Aboriginal Rights – Aboriginal Consultation Office – Authority to Represent Community – Metis Rights – Duty to Consult and Accommodate – Judicial Review Denied

ACO Decision re Consultation

Fort Chipewyan Métis Nation of Alberta, Local 125 ("Local 125") sought to assert on behalf of the Fort Chipewyan Metis Community (the "FCM Community") an aboriginal right of consultation regarding the proposed Teck Frontier Oil Sands Mine (the "Project").

In a January 2015 letter to Local 125, the Alberta Aboriginal Consultation Office (the "ACO") concluded that the Crown's duty to consult Local 125 about the Project had not been triggered (the "ACO Consultation Decision").

Application for Judicial Review

Local 125 applied to the ABQB seeking judicial review of the ACO Consultation Decision.

In the ABQB decision, Justice Goss denied Local 125's application for judicial review. She held that Local 125 failed to provide sufficient information to the ACO that established it was authorized to represent the FCM Community, who held the aboriginal rights being asserted.

The ABQB held that both the ACO's decision and process were within the range of reasonable and acceptable outcomes.

Standard of Review

The ACO submitted that the applicable standard of review was one of reasonableness. The ACO submitted that it acted reasonably in its determination that the GoA would not be requiring consultation with Local 125 based on the information it had provided.

Local 125 submitted that the question as to whether the duty to consult is triggered is a question of law and reviewable on a standard of correctness.

Justice Goss held that the applicable standard of review was reasonableness. She noted that the question as to whether the duty to consult has been triggered is a question of law, generally reviewable on the correctness standard. However, where such a legal issue cannot be considered in isolation from issues of fact, the applicable standard is reasonableness. In this context, a review focuses not on the outcome of the decision, but that all reasonable efforts are made to inform and consult in discharging the Crown duty.

ABQB Denies Judicial Review Application

Justice Goss reviewed the jurisprudence regarding the representation of a Metis community in enforcing its aboriginal right to consultation. She concluded that the applicable test includes the requirement that the organization seeking to enforce an aboriginal claim must demonstrate that it has been authorized to do so by the community it claims to represent.

Justice Goss held, that from the information the Local 125 provided to the ACO, the ACO's determination that consultation was not required was reasonable. Specifically, Justice Goss held that the information provided by Local 125 was insufficient to establish that the organization had authority to represent the aboriginal rights-bearing community, on whose behalf Local 125 sought to assert the community's aboriginal right to consultation.

Justice Goss noted that in addition to Local 125, there were other groups simultaneously seeking to assert the rights of the same Metis community that FCM 125 claimed to represent. The ABQB noted that Local 125 only included about 1/5 of the total members of the FCM Community. The ABQB concluded that on an objective basis, Local 125 failed to establish it was authorized to bring its claim on behalf of the FCM Community.

Further, the ABQB held that the ACO Consultation Decision was made in accordance with a reasonable process that met the procedural fairness obligations required for the Crown to discharge its duty to consult.

The application for review was therefore dismissed.

***Fort McMurray Metis, Local 1935 v. Alberta (Minister of Aboriginal Relations),* 2016 ABQB 712 (December 15, 2016)**
Aboriginal Rights – Aboriginal Consultation Office –– Metis Rights – Duty to Consult and Accommodate – Judicial Review Granted on Natural Justice Grounds

In *Fort McMurray Metis, Local 1935 v. Alberta (Minister of Aboriginal Relations)*, 2016 ABQB 712 (a companion decision to 2016 ABQB 713, summarized above), Justice Goss issued her reasons for granting judicial review of an ACO decision regarding whether the Crown's duty to consult had been triggered.

The question before Justice Goss in this case was very similar as in the previous decision. Specifically, the application for judicial review requested the ABQB review a decision of the ACO, in which the ACO determined that the Crown's duty to consult with Fort McMurray Metis, Local 1935 ("Local 1935") had not been triggered in respect of certain projects in and around the Fort McMurray Metis' traditional territory.

<u>ACO Information Requests and Extension Refusal</u>

On November 24, 2014, the ACO requested further information from Local 1935, including detailed genealogical information about its members.

The ACO requested that Local 1935 respond by December 9, 2014.

On December 1, 2014, the ACO requested a two-week time extension to provide the requested information. On December 5, 2014, Local 1935 provided responses to some of the information requested by the ACO, and requested clarification regarding the requested extension.

On December 9, 2014, the ACO advised that it would not grant the requested extension.

On December 10, 2014, the ACO issued its decision in which it determined that the Crown's duty to consult Local 1935 had not been triggered.

Local 1935 provided information in response to the ACO's request on December 15, 2014, including a large volume of information in electronic form.

The AER issued the licences in February 2015, without requiring further consultation and without holding a hearing.

<u>Application for Judicial Review</u>

Local 1935 applied for judicial review of that ACO decision on the grounds that:

a) The ACO erred in law when it applied an inappropriately high threshold in assessing whether the duty to consult Local 1935 had been triggered; and

b) The ACO erred in law in violating the principles of natural justice and procedural fairness, by:

   (i) failing to consider all the evidence provided by Local 1935;

   (ii) imposing arbitrary and unreasonable timelines on Local 1935 to provide information responses;

   (iii) failing to clarify timelines, failing to respond in a timely manner to extension requests, and refusing to grant reasonable time extensions requested in respect of information requests.

<u>ABQB Decision Granting Judicial Review</u>

Justice Goss held that where there has been a breach of substantive procedural fairness, a court is not to speculate as to how things may have unfolded had the decision maker complied with its duty of procedural fairness. A decision reached by way of an unfair process is rendered void without regard to the correctness or reasonableness of the decision itself.

Justice Goss held that the ACO had breached its duty of fairness by:

a) failing to provide Local 1935 sufficient time to respond to the information it requested;

b) failing to meet its duty in providing clear deadlines within its process; and

c) failing to demonstrate that it fully and fairly considered the information and evidence submitted to it by Local 1935.

The ABQB quashed the ACO decision and remitted the matter back to the ACO.

ALBERTA ENERGY REGULATOR

Request for Regulatory Appeal and Stay of Grizzly Resources Ltd. Licences (AER Appeal No. 1865544)
Request for Regulatory Appeal and Stay of Licences – Regulatory Appeal Request Granted – Stay Denied

On October 11, 2016, the AER issued a decision granting Mike Richard's request, pursuant to section 39 of the *Responsible Energy Development Act* ("*REDA*") for a regulatory appeal of certain well and facility licences issued to Grizzly Resources Ltd. ("Grizzly").

However, the AER denied Mr. Richard's request for a stay of those licences.

Request for Regulatory Appeal

The AER found that Mr. Richard was an "eligible person" within the meaning of that term under *REDA*, and therefore eligible for a regulatory appeal.

The AER did not accept Grizzly's submissions that the request for appeal should be dismissed for being without merit under *REDA* section 39(4). The AER held that a request for appeal should only be dismissed where there is no reasonable evidence for proceeding to the next stage of the appeal proceeding. Specifically, the AER found that Mr. Richard had raised issues that had at least some merit regarding the AER's issuance of the licences without imposing any conditions addressing Mr. Richard's concerns.

The AER also declined to dismiss the appeal request on the basis that Mr. Richard filed the relevant statement of concern ("SOC") past the filing deadline set out in the AER Rules. The AER noted the Rules provide the AER discretion to accept SOCs after the applicable deadline. In this case, the AER held that by soliciting a response from Grizzly regarding Richard's late SOC, it was implied that the AER had permitted the late filing. The AER noted that Grizzly had the opportunity to object to the late SOC at that time, but chose not to.

Request for Stay of Licences

The AER denied Mr. Richard's request for a stay of the licences subject to his appeal request.

In considering whether to grant a stay requested under *REDA* section 39(2), the AER applies the test for judicial stays as set out by the SCC in *RJR MacDonal Inc. v Canada* ([1994] 1 SCR 311) (the "RJR MacDonald Test").

The RJR MacDonald Test is a three-part test, where a court must consider the following questions:

a) whether there is a serious question to be heard at the requested appeal;

b) whether the stay applicant will suffer irreparable harm should the stay request be denied; and

c) which of the parties will suffer greater harm from the granting or refusal of the stay (the balance of convenience question).

The onus is on an applicant (in this case, Mr. Richard) to satisfy all three parts of the RJR MacDonald Test.

The AER held that Mr. Richard satisfied the first part of the test for reasons similar to its finding that there was some merit to Mr. Richard's appeal request.

The AER denied the requested stay on the grounds that Mr. Richard failed to show he would suffer irreparable harm should the stay be granted. The AER noted that Mr. Richard referred to concerns that can be addressed after the new wells and facilities are completed.

In light of its finding to deny the requested stay on the question of irreparable harm, the AER did not consider the third part of the test.

Request for Regulatory Stay of Petrus Resources Corp. Licences (AER Appeal No. 1872471 & 1872809)
Request for Stay of Licences — Stay Denied

On December 16, 2016, the AER issued two decisions denying separate requests from John Winchester and Wayne Greene, requesting the AER stay certain licences issued to Petrus Resources Corp. ("Petrus").

In Mr. Winchester's request, he submitted that the proposed surface location for two well licences was too close to existing residences. He requested that the AER order the locations be moved a mile north, and that pending the appeal request, the licences issued to Petrus be stayed.

Mr. Green requested a stay on similar grounds, also submitting that the licenced wells should be moved a mile north.

AER Decision Denying Stay

With reference to the RJR MacDonald Test described above, the AER denied the requested stays on the grounds that neither Mr. Green nor Mr. Winchester had shown they would suffer irreparable harm.

The AER held that it was not enough for a stay applicant to allege potential harm. Rather, for a stay to be granted, one must show irreparable harm will result. The AER held that neither applicant had provided sufficient evidence to demonstrate the connection between the well and the harm they might suffer, not to mention whether such harm would be irreparable.

Request for Regulatory Appeal of NEP Canada ULC Licences (AER No. Appeal 1862322)
Request for Regulatory Appeal of Licences – Regulatory Appeal Request Denied

On December 7, 2016, the AER issued a decision denying Allen Pukanski's request for a regulatory appeal of certain well licences issued to NEP Canada ULC ("NEP").

Concerns Raised

Mr. Pukanski's submission in support of his appeal request outlined his concerns related to noise, excess flaring, and issues communicating with NEP. Mr. Pukanski submitted that these issues caused health problems, including lack of sleep and stress.

AER Decision

The AER denied Mr. Pukanski's regulatory appeal request on the grounds that he was not an "eligible person" for the purpose of *REDA* section 39.

Specifically, the AER held that the information provided by Mr. Pukanski was general in nature and did not provide specific information showing he would or may be adversely and directly affected by the issuance of the NEP licences. In addition, the AER noted that some of his concerns related to matters that had already been resolved.

ALBERTA UTILITIES COMMISSION

Bulletin 2016-22: New AUC Rule 031: Conditional Exemption from Specific Financing and Reporting Requirements

In Bulletin 2016-22, the AUC announced its approval of AUC Rule 031: *Conditional Exemption from Specific Financing and Reporting Requirements* ("Rule 31).

Rule 31 was approved in Decision 21555-D01-2016 (the "Rule 31 Decision"), and is effective as of December 6, 2016.

The process leading to the decision included submissions from stakeholders on the proposed form of the rule. The AUC directed interested parties refer to the Rule 31 Decision and the Proceeding 21555 e-filing record for additional information on the process and AUC findings respecting Rule 31.

The Rule 31 Decision is also summarized below.

In 2014, the AUC issued Bulletin 2014-09, stating its objective to improve the efficiency of the application and approval process for utilities seeking equity.

Section 101(2)(a) of the *Public Utilities Act,* and Section 26(2)(a) of the *Gas Utilities Act* require certain designated utility owners to apply for approval for the issuance of equity or debt with a maturity period of greater than one year (long-term debt), unless otherwise exempted.

The new Rule 31 is intended to streamline that application process and provide greater certainty to applicants about requirements.

The AUC noted that an objective of the streamlined process is to enhance timely access to debt and equity markets, improve regulatory efficiency, and potentially reduce customers' costs.

Bulletin 2016-21: Enhancements to the AUC's eFiling System for revised documents

In AUC Bulletin 2016-21, the AUC set out a new process for proceeding participants to file revisions to previously filed documents on the AUC e-filing system.

The new process is also reflected in a minor amendment to AUC Rule 001: *Rules of Practice*.

The new Subsection 15.3 of Rule 001 was introduced on November 12, 2016, and provides:

> 15.3 When a party intends to file a revised document with the Commission, the party must complete a revised document description form on the eFiling System and file:
>
> (a) the revised document, and
>
> (b) a blackline version of the revised document that tracks each of the differences between the latest version and the original version.

Decision 20622-D01-2016 re 2016 Generic Cost of Capital (October 7, 2016)

Rates – Electricity/Gas – Distribution/Transmission Deemed Cost of Capital – Debt/Equity Ratio – Return on Equity (ROE) – Capital Markets

In Decision 20622-D01-2016 (the "2016 GCC Decision"), the AUC set out:

a) the allowed return on equity ("ROE"); and

b) the approved debt equity ratios,

for the years 2016 and 2017 on a final basis.

<u>The Approved GCC and the Affected Utilities</u>

The 2016 GCC Decision applies to the following electricity and natural gas transmission and distribution utilities:

- AltaLink;
- ATCO Electric Transmission;
- ATCO Pipelines;
- ENMAX Transmission;
- EPCOR Transmission;
- Lethbridge;
- Red Deer;
- AltaGas;
- ATCO Electric Distribution;
- ATCO Gas;
- ENMAX Distribution;
- EPCOR Distribution; and
- FortisAlberta,

(the "Affected Utilities").

The 2016 GCC Decision does not apply to utilities regulated under the *Electric Utilities Act Regulated Rate Option Regulation* or the *Gas Utilities Act Default Gas Supply Regulation*, as those regulations specifically prescribe the determination of reasonable rates of return for such utilities.

Although the 2016 GCC Decision does not apply specifically to water utilities, the AUC held that the determinations set out in the 2016 GCC Decision may be considered in any cost of capital determination regarding investor-owned water utilities.

AUC Approach to Setting Allowed ROE and Deemed Equity Ratios

The AUC's explained its approach as establishing an ROE that applies uniformly to the Affected Utilities. However, to account for variation in business risk faced by individual utilities, the AUC may approve deemed equity ratios on an individual basis.

In making its determination of a fair ROE, the AUC considered changes in the global and Canadian capital markets conditions since the previous AUC Decision 2191-D01-2015 re 2013 Generic Cost of Capital (the "2013 GCC Decision").

The AUC went on to examine the relationship between capital structure (i.e. debt/equity ratio) and ROE, with respect to establishing a fair ROE for the Affected Utilities.

Capital Markets and Changes since 2013

The AUC received expert written evidence and testimony from a variety of experts sponsored by the Affected Utilities, the Utilities Consumer Advocate (the "UCA"), the Canadian Association of Petroleum Producers ("CAPP"), and the Consumer Coalition of Alberta (the "CAA").

Those experts presented evidence regarding changes in macroeconomic factors since the 2013 GCC Decision, including:

a) Withdrawal of monetary stimulus in the U.S. due to accelerating growth of the U.S. economy;

b) Sharp decline in oil and other commodity prices;

c) Slowdown in the Chinese economy and other developing markets; and

d) Strengthening of the U.S. dollar (USD) relative to the Canadian dollar (CDN).

Modeling a Fair ROE

The experts all provided estimations for a fair ROE using empirical models, including:

a) Capital asset pricing models ("CAPM"), which estimate a fair ROE by:

   (i) estimating a risk-free rate ("R_f") (e.g. long-term government bond yield);

   (ii) estimating of market equity risk premium ("MERP"), which represents the premium an investor requires to address the risk that an expected return will not be achieved.

   (iii) A CAPM model then estimates a ROE in accordance with the formula:

$$R_e = R_f + \beta[E(R_m) - R_f],$$

Where:

R_e = required ROE for investors to invest;

R_f = the risk-free rate;

$E(R_m) - R_f$ = MERP; i.e. expected market return minus risk-free rate; and

β = coefficient measuring sensitivity of R_e to MERP (usually derived from historical data).

b) Discounted cashflow (DCF) models, which estimate ROE as:

$$R_e = {}^{D_1}/_{P_0} + g,$$

Where:

R_e = the required return on common equity;

D_1 = the next period's expected dividend;

P_0 = the current period common share price; and

g = the expected long-term growth rate in dividends.

AUC Determinations

The AUC considered the parties' submission and expert evidence respecting changes in risk faced by the Affected Utilities (and their investors) in the period since the 2013 GCC Decision. The AUC generally considered the directional effect of the evidence, rather than adopting any of the specific estimated values proposed by the various experts.

The AUC found that yields on utility bonds were lower now than in the period considered in the 2013 GCC proceeding, due in part to lower rates of inflation and foreign investors pursuing lower risk investments. The AUC held that this evidence suggested downward pressure on the return required by utility equity holders, everything else equal. This conclusion flows from evidence showing that the expected return on utility bonds (yields) and required return for utility equity investors are positively correlated.

On the other hand, the AUC found that utility bond holders are now facing more risk compared to what they were facing in the period prior to the 2013 GCC proceeding, as evidenced by the increase in utility credit risk spreads between utility bond holders and equity investors. All other things equal, this finding suggested an upward pressure on the return required by utility investors.

The AUC considered these factors to off-set each other. The AUC determined that a fair generic return on equity for the Affected Utilities is 8.30 per cent for 2016, which is the same as the ROE approved in the 2013 GCC Decision.

The AUC also held that economic conditions were generally expected to improve in 2017, including an expected increase in interest rates.

The AUC concluded that it would allow an increase in the ROE for 2017 of 0.2 percent, for an allowed ROE in 2017 of 8.50 percent. The 8.50 percent allowed ROE for 2017 will remain in place on an interim basis in 2018 and beyond until the next GCC decision.

Deemed Debt/Equity Ratios

Consistent with past GCC decisions, the AUC awarded common equity ratios that, on a stand-alone basis, are consistent with credit ratings in the A category.

The AUC considered a number of credit metrics to determine an equity ratio consistent with a capital structure that allows a utility to maintain A category credit rating. In reaching its determination, the AUC held that the funds for operations (FFO)/deb ratio is an important, if not the most important, metric in the assessment of a regulated utility's creditworthiness.

The AUC considered evidence that utility's S&P credit rating will be down graded if the FFO/debt ratio falls below 14%. The AUC determined that a FFO/debt ratio between 11.1 to 14.3 per cent was consistent with targeting a credit rating in the "A" range. The AUC held that given the other relevant parameters, including other credit metrics, tax rates, ROE (described above), and other measures of business risk, a deemed equity ratio of 37% was generally consistent with a ratio consistent with A range credit.

Due to the relatively small size of AltaGas (and therefore higher business risk), the AUC approved for AltaGas a deemed equity percentage 400 bps higher than the deemed equity ratio for the average distribution utility.

The AUC did not continue previously approved equity ratio premiums for distribution companies subject to performance based regulation. The AUC held that such a premium was not warranted given that such utilities had not experienced any appreciable increase in earning volatility risk – on which previous equity ratio premiums were premised.

Neither did the AUC continue the previously approved 200 bps equity ratio premium for tax-exempt utilities, which was sought to address increased business risk associated with higher earnings. The AUC held that even without a premium for utilities not paying income tax, such utilities would still qualify for credit ratings in the A range with a deemed equity ratio of 37%.

The following table provides a summary of the approved deemed equity ratios for each of the Affected Utilities, compared to the previously approved ratios.

Table 1: AUC Approved Deemed Equity Ratios

Company	2016-2017 Approved Equity Ratio	Previously Approved in 2013 GCC Decision	Change
Electricity and natural gas transmission			
AltaLink	37	36	+1
ATCO Electric Transmission*	37	36	+1
ATCO Pipelines	37	37	
ENMAX Transmission*	37	36	+1
EPCOR Transmission	37	36	+1
Lethbridge	37	36	+1
Red Deer	37	36	+1
TransAlta	37	36	+1
Electric and gas distribution			
AltaGas	41	42	-1
ATCO Electric Distribution	37	38	-1
ATCO Gas	37	38	-1
ENMAX Distribution*	37	40	-3
EPCOR Distribution	37	40	-3
FortisAlberta	37	40	-3

* Approved on a placeholder basis.

Decision 20414-D01-2016 re 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities (December 16, 2016)
Rates – Performance Based Regulation (PBR) – Electricity/Gas Distribution – Next Generation PBR Parameters

In Decision 20414-D01-2016 (the "2016 PBR Decision"), the AUC determined the parameters that apply to the next generation of performance based regulation ("PBR") plans. The parameters the AUC approved in the decision apply for the 2018-2022 PBR term.

The 2016 PBR Decision applies to the following electricity and gas distribution utilties:

- ATCO Electric Ltd.;
- ENMAX Power Corporation ("ENMAX");
- EPCOR Distribution & Transmission Inc.;

- FortisAlberta Inc.;
- AltaGas Utilities Inc.; and
- ATCO Gas and Pipelines Ltd.;

(collectively, the "PBR Utilities").

However, due to ENMAX being subject to an individual incentive based regulation plan, certain AUC holdings were individualized to ENMAX's unique plan. Those differences are not discussed in this summary.

PBR Plan Overview

The 2016 PBR Decision did not alter the general PBR framework, as set out in AUC Decision 2012-237 (the "2013 PBR Decision").

The PBR framework approved in the 2013 PBR Decision provides for annual rates adjustments based on an indexing mechanism (the "I-X Mechanism") that tracks the rate of inflation ("I Factor") less a productivity offset ("X-Factor"). The I-Factor is designed to represent the expected increase in the price of inputs and therefore a positive I-Factor results in higher rates. However, the I-Factor is offset by the X-Factor, which represents the expected efficiency improvements the PBR Utilities are expected to achieve during the PBR plan period.

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

The rate setting mechanism set out in the 2013 PBR Decision is expressed by the following formula:

$R_t = R_{t-1}(1 + (I - X)) \pm Z \pm K \pm Y$,

Where:

- R_t = upcoming year's rate for each class;
- R_{t-1} = current year's rate (i.e. excludes rate rider adjustments);
- I = I-Factor (inflation/cost of inputs adjustment);
- X = X-Factor, which reflects the productivity improvements the utility can expect to achieve during the test period;
- Z = exogenous adjustments ("Z-Factor"), which include material events for which the company has no other reasonable cost recovery mechanism;
- K = capital trackers collected directly from customers through K factor rate adjustment ("K Factor"), including amounts to fund necessary capital expenditures; and
- Y = flow through items collected through the Y factor rate adjustments ("Y-Factor").

The I-Factor approved in the 2013 PBR Decision was continued unchanged in the 2016 PBR Decision. The I-Factor continues to be determined by the formula:

$$I_t = 55\% * AWE_{t-1} + 45\% * CPI_{t-1};$$

where:

I_t = the inflation factor for the following year;

AWE_{t-1} = the Alberta average weekly earnings (AWE) index for the previous July though June period; and

CPI_{t-1} = the consumer price index (CPI) for the previous July though June period.

Scope of 2016 PBR Decision and Significant Holdings

In the 2016 PBR Decision, the AUC limited the scope of the proceeding to consideration of four PBR plan parameters, namely:

1. rebasing and the going-in rates for the next generation PBR term (2018-2022),
2. the X-Factor,
3. the treatment of capital additions (previously, the K-Factor), and
4. the calculation of the return on equity ("ROE") for reopener purposes.

Significant changes approved in the 2016 PBR Decision for the next generation of PBR plans include:

- a requirement that going-in rates be based on actual costs experienced in the previous term and not on forecasted costs for the next term;
- a determination that the X-Factor (inclusive of a productivity growth and stretch factor) will be equal to 0.3 percent for the next PBR term, a reduction from the 1.16 percent approved in the 2013 PBR Decision; and
- changes to the capital funding mechanism, whereby most capital additions will be funded through a mechanism tied to the I-X Mechanism (the K-bar parameter) rather than being COS based, as is the case for the K-Factor.

A more detailed summary of the AUC's findings is provided below.

Rebasing and Going-in Rates

The AUC directed that going-in rates be based on actual costs experienced during the current generation PBR term, with any necessary adjustments to reflect individual utility's circumstances.

The AUC rejected the use of forecasted costs in determining PBR going-in rates noting that:

a) setting going-in rates based on forecast costs may create incentives to over-forecast, limiting potential benefits to customers from PBR plan re-basing; and

b) testing cost forecasts would require the same level of detail as in traditional COS proceedings, contrary to the purpose of PBR to improve efficiency and reduce regulatory burden.

The AUC directed each of the Affected Utilities to file by March 31, 2017, an application to determine a notional 2017 revenue requirement, on which going-in rates are to be based ("Going-in Rates Application(s)").

The AUC directed that such an application calculates the going-in rate base based on the average actual capital additions for years of the current generation PBR plans, excluding the last year, restated to 2017 dollars.

Specifically, a Going-in Rates Application's proposed notional rate base must:

a) use the actual 2016 closing rate base, as the starting point;

b) adjust the rate base by removing utility assets as directed in prior asset disposition decisions;

c) add to the 2016 closing rate base, the average actual capital additions for years 2013 to 2016;

d) for the capital tracker component, add the approved 2017 forecast capital tracker capital additions to the 2016 closing rate base; and

e) apply 2017 depreciation using the distribution utility's most recent approved depreciation methodologies applied to notional rate base as determined in (a)-(d).

The AUC further directed that the O&M part of the revenue requirement be based on the lowest actual annual O&M expenditures experienced during the 2013-2017 PBR term. The AUC approved the use of a Q-factor, which allows for adjustments to O&M expenses due to customer growth.

Phase II applications will be accepted for consideration sometime following the commencement of the next generation PBR plans. Any changes to rates approved in Phase II applications – e.g. requesting the AUC consider a new COS or depreciation study – will only apply on a prospective basis.

Efficiency Carry-over Mechanism

The AUC noted that a utility's incentive to find efficiencies weakens as a PBR term nears an end, unless there is an efficiency carry-over mechanism ("ECM"). An ECM seeks to incent late term efficiency improvements by providing an associated financial "reward" carried-over into the subsequent PBR term.

In the 2013 PBR Decision, the AUC approved an ECM that functions as on add-on to an approved ROE for an applicable year. Specifically, the approved ECM is ROE-based, equal to one half the difference between a utility's average actual ROE achieved over the 2013-2017 PBR term and the average approved ROE over that term.

In this 2016 PBR Decision, the AUC adopted EPCOR's proposal whereby the ECM ROE add-on is applied to the 2017 mid-year rate base, and escalated by the approved I-X value for each of the subsequent years 2018 and 2019.

X-Factor: Total Factor Productivity (TFP) Growth and Stretch Factor

The X-Factor is comprised of two components:

1. a total factor productivity growth ("TFP") factor, representing average rate of long term productivity growth in the industry; and

2. a stretch factor, which is an additional percentage included in the X-Factor which slows the revenue cap growth under the I-X Mechanism. A stretch factor can be viewed as sharing with customers the expected cost reductions resulting from the transition from COS to PBR.

With respect to TFP growth, the AUC considered evidence and estimations of such values from various experts.

The AUC noted the considerable variability in the experts' estimates, resulting from the variation in choice of assumptions employed in each expert model. The AUC concluded, that based on such evidence, the TFP growth factor falls within a reasonable range of values, between -0.79 and +0.75.

The AUC held that a reasonable X factor for the next generation PBR plans for the PBR Utilities, inclusive of a stretch factor, is 0.3 per cent.

The AUC did not adopt the UCA's proposal to restrict the I-X Mechanism to being non-negative. The AUC noted that such an approach may result in weaker incentives to control costs for certain categories of expenditures.

Type 1 Capital Projects

The AUC approved a capital funding mechanism whereby capital projects are categorized as either Type 1 or Type 2.

Type 1 capital trackers, which replace the original capital tracker criteria established in AUC Decision 2013-435 (K-Factor treatment criteria), require a project to be:

(i) of a type that is extraordinary and not previously included in the distribution utility's rate base; and

(i) required by a third party,

(the "Type 1 Project Criteria").

The placeholder for Type 1 projects or programs will be calculated as 90 per cent of the management-approved internal forecast for that year. This forecast will not be tested for reasonableness because the prudence of such amounts will be considered in Type 1 capital tracker true-up applications.

<u>Type 2 Capital Projects and K-Bar Parameter</u>

Type 2 capital projects are all other capital additions that do not meeting the Type 1 Project Criteria.

For Type 2 capital additions, the AUC directed an initial K-bar capital factor ("$\bar{K}_0$") would be established as the incremental capital funding for all Type 2 capital in 2018. The base K-bar would be calculated by using an accounting test similar in concept to the test used during the 2013-2017 PBR term, represented by following formula:

$$\bar{K}_t = \bar{K}_{t-1} x\,(\bar{K}_0) * \left(1 + (I_t - X) * (1 + (I_{t-1} - X)\right) \ldots$$

Where:

$\bar{K}_t$ = K-bar factor for current year;

$\bar{K}_{t-1}$ = K-bar from the previous year;

$\bar{K}_0$ = 2018 base K-bar;

I_t = inflation factor for current year;

I_{t-1} = inflation factor from the previous year;

X = productivity factor; and

$(1 + (I_{t-1} - X)) \ldots = (1 + (I_{t-1} - X)$ multipliers for all previous years.

<u>Calculation of ROE for the Re-opener Threshold</u>

The AUC held that it will continue to utilize an allowed ROE for a given year as the "base" ROE. The base ROE will be equal to the approved ROE as determined in a generic cost of capital proceeding (see above for summary of 2016 GCC Decision summary).

That base ROE is to be compared against a utility's actual return to determine the applicable reopener value for that year.

The AUC held that it will employ a +/-500 basis point threshold for a single year and +/-300 basis point threshold for two consecutive years as warranting consideration of a reopening and review of a PBR plan.

***Decision 790-D05-2016* re Milner Line Loss, Phase 2 Module B, AESO Compliance Filing (November 30, 2016)**
ISO Line Loss Rule – Electricity – Loss Factor Methodology – Behind-the-Fence Generation

In this decision, the AUC approved the AESO new line loss rule, as filed.

The AUC held that when calculating loss factors, the AESO should use the full range of net-to-grid output of each generating facility.

The AUC further held that a net-to-grid approach should also apply to behind-the-fence generation, such as industrial users and the City of Medicine Hat ("CMH").

The AUC rejected the submissions of CMH and others that argued the line loss rule should consider gross amounts with respect to behind-the-fence generation. The AUC held that the relevant factor is electric energy that is exchanged with the transmission system (i.e the AIES).

On this basis, the AUC approved the AESO's net-to-grid approach set out in Section 8: *Calculation of Hourly Loss Factors* of the new line loss rule, finding that the proposed rule "correctly uses the net generation of a generating facility when calculating loss factors."

GOVERNMENT OF ALBERTA ELECTRICITY MARKET REFORM

Introduction

The legislative and regulatory scheme governing the regulation of the Alberta electricity industry is undergoing significant changes as a result of the Government of Alberta ("GoA")'s Climate Leadership Plan (the "CLP"). As part of the CLP, the GoA is implementing a renewable electricity plan ("REP").

The GoA tasked the AESO with designing and implementing the REP. Pursuant to this mandate, the AESO provided its recommendations set out in the report: *Renewable Electricity Program Recommendations* (the "REP Report"). Although the REP Report was submitted to the GoA in May 2016, it was not publicly released until November.

On November 3, 2016, the GoA endorsed the AESO's REP Report, announcing that it will solicit 5,000 MW of renewable generation capacity through a series of competitive bidding processes as part of the REP. Procurement of new renewable generation through the REP is to be aligned with the planned phase-out of coal-fired generation. The first round of generation capacity procurement through the REP is to be for 400 MW.

We provide herein a summary overview of the REP as described in the AESO's REP Report.

We also provide a brief summary of another AESO report titled *Alberta's Wholesale Electricity Market Transition Recommendation* (the "Capacity Market Report"). The Capacity Market Report was released by the GoA on November 23, 2016, shortly after the public release of the REP Report.

AESO Report: *Renewable Electricity Program Recommendations* (May, 2016; publicly released November 3, 2016)
Renewable Electricity – Market Design – Capacity Procurement

Eligibility

The AESO Report recommends that the REP be limited to:

(i) Renewable generation, as defined by Natural Resources Canada;

(ii) Projects with generation capacity ≥ 5 MW; and

(iii) New or expanded projects that physically reside in Alberta.

Competitive Procurement Process

The AESO REP Report recommends that each round of REP generation procurement consist of the following three stages:

(i) A Request for Expressions of Interest ("REI"), a discretionary stage where the AESO can gauge interest in participating in the competition;

(ii) A Request for Qualifications ("RFQ"), where bidders submit their qualifications including their project proposals; and

(iii) A Request for Proposals ("RFP"), where bidders qualified in the preceding stage confirm no changes to their bid team or their projects and submit a final offer for support.

Payment Mechanism

The AESO REP Report recommends an indexed Renewable Energy Credit ("IREC"), whereby a winning bidder is paid \$/MWh payment for its renewable energy attributes ("REA").

Under the IREC scheme:

(i) Each bidder in the RFQ process submits a price (\$/MWh) representing the lowest acceptable payment (the "Bid Price"), which will allow that proponent to proceed with development of their proposed project;

(ii) The support payment (i.e. subsidy) is based on each winning bidder's Bid Price net of the price that bidder would receive with no subsidy (i.e. pool price); and

(iii) Therefore, the IREC payment is equal to the Bid Price minus the pool price.

It is possible under the scheme for the IREC to be negative. If the pool price is above the Bid Price, a winning bidder may end paying to the AESO the difference, as opposed to receiving a positive difference as an IREC payment by the AESO to a generator.

AESO Report: *Alberta's Wholesale Electricity Market Transition Recommendation* (October 3, 2016; publicly released November 23, 2016)
Capacity Market – Market Design – Incenting Investment

This report states that investor confidence in Alberta's electricity industry has become a significant issue in recent years. Factors contributing to that uncertainty include concerns about the present price volatility in the energy only market and the negative (or uncertain) effects of the CLP (including the out-of-market REP), as it is developed and implemented. The AESO's recommended transition to a capacity market comes amidst concerns that Alberta's energy only electricity market will not, on its own, incent sufficient investment in new generating capacity to reliably meet Alberta's future needs.

In the AESO Capacity Market Report, the AESO states that the transition to a capacity market is intended to incent investment in new generating capacity in Alberta.

Capacity Market Overview

In the Capacity Report, the AESO does not provide recommendations as to the specific form the Alberta capacity market should take. However, there are a number of key components in any capacity market design, including:

- Establishing a market for installed capacity – i.e. a payment mechanism for the installed and available capacity of a facility and paid independently to any revenue a generator receives from the energy it produces;
- Determining the reliability target and therefore the quantity of capacity to be procured through a capacity market mechanism;
- Establishing the entity responsible for system capacity planning and setting the size of the capacity market (e.g. the AESO); and
- Determining the mechanism by which capacity will be procured (e.g. through auction) and payments will be made (e.g. payment of $/MW/settlement period, as a function of successful bidders' bid price).

In the Capacity Market Report, Appendix D: *Capacity Markets: Key Design Considerations,* the AESO notes the following details that have yet to be determined:

- Resource eligibility, including:
    - whether existing or only new facilities will be eligible;
    - the "firmness" of a resource (especially significant with respect to intermittent sources); and
    - treatment of demand side "capacity," such as whether energy efficiency measures will be eligible to bid in the capacity market;
- Whether and to what extent the capacity market will be segmented by location or technologies;
- the level of any price caps or floors;
- Measures to mitigate excessive market power and compliance monitoring/enforcement;
- the provision of data to market participants;
- Role of secondary market; and
- Allocation of capacity costs amongst load customers and the collection of such costs.

Compatibility of Capacity Market with REP

The AESO states that "the introduction of a capacity market would not jeopardize achieving the renewable targets as set out by the government" through the REP as recommended by the AESO.

A capacity market will have a negative effect on prices in the energy only market, all other things being equal. Capacity market payments represent a payment towards a generator's fixed costs to build that capacity and are paid independently of any energy actually produced. A generator receiving capacity payments can therefore make the same profit selling electricity in the energy market at a lower price because of the additional revenue it receives from capacity payments.

The AESO notes that the IREC mechanism insulates REP generators from this downward pressure on electricity prices, as they are guaranteed a certain price for electricity sold under the terms of an REP agreement. REP generators would therefore not be affected by any decrease in energy prices resulting from the transition to a capacity market.

However, existing renewable generators not part of the REP will likely be adversely affected by the capacity market due to lower energy prices and the limited potential value of intermittent renewables in a firm capacity market.

Similarly, the capacity market's effect on existing non-renewable generators will depend on whether such existing generators will be eligible to participate in the capacity market. If not eligible, the capacity market's downward effect on energy prices will adversely affect existing generators not eligible for capacity payments or the REP.

NATIONAL ENERGY BOARD

NEB Reasons for Decision: TransCanada Mainline Tariff Amendment Application re Storage Transportation Service, Reasons for Decision (Hearing Order RH-001-2016)

Toll and Tariffs – Natural Gas – TransCanada Mainline System – NEB Denies Amendment Application

On February 18, 2016 TransCanada PipeLines Limited ("TCPL") submitted an application (the "Application") to the NEB requesting approval of proposed amendments to its tariff respecting the Canadian Mainline Gas Transportation System (the "Mainline System").

Specifically, TCPL requested the NEB approve its proposed amendments to the tariff in respect of Storage Transportation Service ("STS"), the elimination of Storage Transportation Service-Linked ("STS-L"), and the implementation of a proposed shipper election process.

The NEB denied TCPL's application for the reasons summarized below.

<u>Mainline Tariff Background</u>

The NEB provided a summary of significant changes and developments to the Mainline System tariff over the past five years.

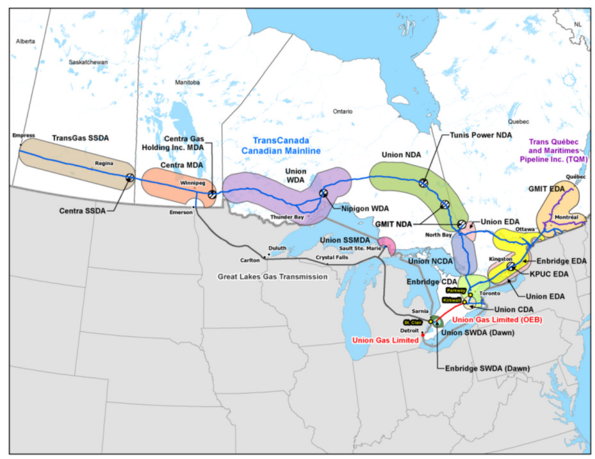
In the RH-003-2011 Decision, the NEB granted TCPL tools to better manage its system and respond to toll increases and the eroding competitiveness of the Mainline System.

In the period following the RH-003-2011 proceeding, extensive litigation and a need for capital investment resulted in the 2013-2030 Settlement Agreement (the "Mainline Settlement").The NEB approved the Mainline Settlement in the RH-001-2014 Decision (the "2014 Mainline Settlement Decision"), which further restructured the Mainline and included an update to Mainline tolls for the 2018 to 2020 period. Among other things, the 2014 Mainline Settlement Decision approved the following:

- the proposed revenue requirements and rate base components for the 2015 to 2020 period, subject to a review of forecast assumptions for the 2018 to 2020 period;
- the proposed incentive sharing mechanism that has both upside and downside risk for the Mainline on a year-to-year basis, and includes a contribution from TransCanada;
- Segmentation of the Mainline in principle post-2020, such that the Eastern Triangle will be separate from the Northern Ontario Line and the Prairies Line.

The NEB noted segmentation of the Mainline post-2020 "as being on the horizon." That segmentation will involve its own challenges as stakeholders confront a comprehensive change to toll design. Further developments on the Mainline may also materialize as TransCanada continues to innovate and respond to new challenges and opportunities.

Figure 1: Map of Mainline System and Segments



<u>Parties' Submissions</u>

Centra Gas Manitoba Inc., Enbridge Gas Distribution Inc., and Union Gas Limited opposed the Application, while Société en commandite Gaz Métro (Gaz Métro) did not. However, the NEB generally heard from interveners that the Application was premature and that STS should instead be reviewed comprehensively during the Mainline tolls and tariff proceeding for the post-2020 period.

TCPL submitted that the proposed changes were intended to modernize and standardize STS, improve alignment between cost causation and cost responsibility, and improve equity amongst all shippers.

<u>NEB Decision and Reasons</u>

The NEB held that as a result of the Mainline Settlement, shippers expected a reasonable level of toll certainty and stability for the applicable period. One such expectation, was that shippers that made Long-Haul Firm Transportation commitments would not face significant changes to or increased costs for the provision of STS.

Further, given the upcoming matter of Mainline segmentation, the NEB held that it would be unfair and inequitable to STS shippers to impose significant adjustments to their gas transportation portfolios, or to impose significant costs and reductions to flexibility that likely cannot be mitigated.

The NEB therefore denied TCPL's application to amend the Mainline System tariff and eliminate STS-L.