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DECISIONS

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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FEDERAL COURT OF APPEAL

Tseil-Waututh Nation v National Energy Board
Trans Mountain Pipeline – Duty to Consult – NEBA – CEAA 2012 – Environmental Assessment

The Tsleil-Waututh Nation ("TWN") appealed from three interlocutory decisions of the NEB in the context of the NEB's review of Trans Mountain Pipeline ULC ("TM")'s application for the construction of a pipeline project (the "Project").

The proposed Project consists of an extension to the existing TM pipeline system, including 987km of new buried pipelines, reactivation of 193km of existing pipeline, and construction of associated facilities.

The Decisions were described by the Federal Court of Appeal ("FCA") as:

1. A determination that TM's application was complete (the "Completeness Decision");

2. A confirmation that the Project is a "designated project" for the purposes of requiring an environmental assessment pursuant to the *Canadian Environment Assessment Act, 2012* (*CEAA 2012*) (the "Designation Decision"); and

3. An order detailing process steps, including a public hearing (the "Hearing Order"),

   (collectively, the "Decisions").

The TWN raised the following four issues on appeal:

1. Does the NEB, when acting as a responsible authority under the *CEAA 2012*, have the authority and obligation to discharge the Crown's duty to consult with Aboriginal groups?

2. Did the NEB breach its obligation to consult and collaborate with TWN as a "jurisdiction" within the meaning of *CEAA* 2012, section 18?

3. Did the NEB breach its duty of fairness to the TWN by failing to obtain its consent in respect of all the issues raised in the Decisions?

4. Did the NEB err in law by failing to include marine shipping activities in the Designation Decision?

The FCA dismissed TWN's appeal without prejudice to the TWN's right to raise the same issues in any proceeding TWN deems necessary to contest the ultimate decision of the Governor in Council ("GIC").

<u>Duty of Fairness</u>

The TWN initiated the appeal proceedings pursuant to the statutory right of appeal contained in the *National Energy Board Act* ("*NEBA*") section 22(1). The FCA noted that while certain interlocutory decisions of the NEB are final and can be properly appealed under *NEBA* section 22(1), the Decisions were not final and therefore appeal to the FCA was premature.

With respect to the Completeness Decision, the FCA noted that the NEB's determination that an application is complete does not preclude participants from making submissions regarding what they consider to be deficiencies in an application. Rather, a finding of completeness by the NEB is an initial threshold question and an application will be considered "complete" if there is sufficient detail to engage public debate through the hearing process.

The FCA noted that the Completeness Decision was open to variation by way of a motion at any time before the commencement of final argument. TWN did not follow the process set by the NEB to raise its concerns and thus did not avail itself of its right to be heard.

With respect to the Designation Decision, the FCA noted that, similarly to the Completeness Decision, the Designation Decision was open to variation upon interveners' motions. The FCA noted that TWN did not present its concerns to the NEB prior to its appeal to the FCA.

The FCA also noted that in the list of issues made public in July 2013 (after the issuance of the Designation Decision), the NEB included on the list the impact of increased maritime shipping. The NEB also included the cumulative effects of increased shipping as a consideration for the environmental assessment under *CEAA 2012.*

The FCA held that TWN failed to establish any breach of duty of fairness with respect to the Hearing Order. Specifically, the TWN failed to explain why the process chosen by the NEB (allowing all interveners to make requests by motion) was not sufficient to meet the NEB's duty to act fairly in a massive proceeding involving over 400 interveners.

The FCA noted that had TWN felt it was prejudiced by any part of the Hearing Order it was open to TWN to file a motion with the NEB raising such concerns. The TWN never filed such a motion.

Duty to Consult

The FCA noted that TWN had not raised any Constitutional issues regarding the adequacy of consultation to the NEB before commencing the appeal. The FCA reiterated previous findings of the FCA emphasizing the importance of not bypassing the administrative process when dealing with Constitutional issues.

TWN submitted that it needed to raise a potential breach of the Crown's duty to consult at the earliest possible opportunity in order to obtain an effective remedy.

The FCA rejected this argument, and noted that if anything, the route chosen by TWN to address its consultation concerns caused significant delay and the TWN did not conduct itself as if a decision in the FCA proceeding was urgent.

The appeal was dismissed without prejudice to the TWN raising issues related consultation and accommodation once the GIC makes its decision on the basis of the NEB's recommendations.

ALBERTA COURT OF APPEAL

Orphan Well Assn. v Grant Thornton Ltd.
Intervener Standing – Doctrine of Federal Paramountcy – Oil and Gas Conservation Act – Pipelines Act – Bankruptcy and Insolvency Act – Licensee

The Canadian Association of Petroleum Producers ("CAPP"), the Canadian Association of Insolvency and Restructuring Professionals ("CAIRP"), the Attorney General for Saskatchewan ("Saskatchewan"), Her Majesty the Queen in Right of the Province of British Columbia as represented by the Ministry of Natural Gas Development and the British Columbia ("BC") Oil and Gas Commission (the "BC Applicants") (collectively, the "Intervener Applicants"), sought leave from the Alberta Court of Appeal ("ABCA") to participate as interveners in a Constitutional appeal concerning division of powers and the doctrine of paramountcy.

In this decision, Martin J.A. granted all four entities permission to participate in the ABCA proceedings, subject to certain conditions.

ABQB Decision

The ABCA proceedings considered the decision of Alberta Court of Queen's Bench ("ABQB") Chief Justice Wittmann in *Redwater Energy Corporation (Re)*, 2016 ABQB 278 (the "ABQB Redwater Decision"). In the ABQB Redwater Decision, Redwater Energy Corporation ("Redwater")'s trustee and receiver in bankruptcy sought to disclaim certain of Redwater's non-producing wells pursuant to section 14.06 of the federally enacted *Bankruptcy and Insolvency Act* (the "*BIA*"). Section 14.06 of the *BIA* permits a trustee in bankruptcy to renounce unprofitable assets without the responsibility for environmental abandonment and remediation work.

The AER and the Orphan Wells Association (the "OWA") jointly applied for a declaration from the court that the receiver's renouncement of well assets was void and unenforceable, due to the environmental remediation work necessitated as a result of the well abandonment.

The AER and OWA sought an order compelling the Receiver to fulfill its obligations as a licensee under the *Oil and Gas Conservation Act* ("*OGCA*") and the *Pipeline Act* ("*PA*") in relation to abandonment, reclamation, and remediation of Redwater's licensed properties.

In the ABQB decision, Wittman C.J. found that compliance with both the provincial legislation (i.e. the *PA* and *OGCA*) and the federal *BIA* was impossible. Therefore, the Chief Justice held that the doctrine of federal paramountcy was triggered. He declared the definitions of licensee under the *PA* and *OGCA* to be inoperable to the extent that those definitions frustrated the purpose of the *BIA.* It followed that the remedies sought by the AER and OWA were denied.

The AER and OWA appealed, and on June 29, 2016, the ABCA granted leave to appeal. The Intervener Applicants subsequently applied to the ABCA for permission to participate as intervenors in the proceedings.

Test for Permission to Intervene

In this ABCA procedural decision, Martin J.A. summarized the two-part intervener test as set out in *Pedersen v Van Thournout*, 2008 ABCA 192 (the "Pedersen Test"). Under the Pedersen Test, a court must first consider the subject matter of the appeal and then determine the proposed intervener's interest in it.

In determining the proposed intervener's interest, the court must examine whether the proposed intervener:

(a) will be directly and significantly affected by the appeal's outcome; and

(b) will provide some expertise or fresh perspective on the subject matter that will be helpful in resolving the appeal,

(the "Pedersen Test").

A proposed intervener must satisfy both parts of the Pederson Test in order to satisfy the test and be granted permission to participate in an appeal as an intervener.

The BC Applicants

Justice Martin held that the BC Applicants met the criteria for permission to intervene.

While the BC Applicants played no part in the lower court proceedings, they sought leave to appeal submitting that Alberta receivership orders directly affect the BC regulator when an Alberta insolvent has assets in BC. Additionally, the outcome of the appeal regarding the interpretation of section 14.06 of the *BIA* could affect the interpretation and application of BC provincial legislation, directly impact the regulatory regime in BC, the BC orphan fund, and BC taxpayers.

Justice Martin held that the BC Applicants would be directly and significantly affected of by the outcome of the appeals. In addition, he found that the BC Applicants would bring an extra-provincial perspective and discuss additional case authorities that would be helpful to the ABCA in its interpretation of the *BIA*.

<u>CAPP</u>

Justice Martin held that CAPP satisfied the Pederson Test and granted leave to CAPP to participate in the appeal as an intervener and make submissions in support of the appellants (the AER and OWA). CAPP did make submissions in the court below.

Martin J.A. explained that CAPP members are the primary source of funding for both the orphan fund and the AER. As a result, the appeal directly affects the members of CAPP.

With respect to the second part of the Pedersen Test, Justice Martin stated that in using its "broad voice of industry," CAPP would bring a different and broader perspective regarding the issues that differ from the appellants, or which the appellants might be restrained in making.

<u>Saskatchewan</u>

Saskatchewan was granted leave to participate in the appeal as an intervener on behalf of the appellants.

Saskatchewan did not participate in the lower court proceedings. Justice Martin held that Saskatchewan's orphan well program, its oil and gas industry, and taxpayers would be negatively affected if the ABQB Redwater Decision were upheld on the appeal.

Justice Martin also accepted Saskatchewan's submissions that by focusing on common law bankruptcy and broader principles regarding co-operative federalism, Saskatchewan would bring fresh perspectives on arguments helpful to the ABCA. It followed that Saskatchewan met the criteria for permission to participate as an intervener in the appeal.

<u>CAIRP</u>

CAIRP was granted leave to participate in the ABCA proceedings and make submissions in support of the respondent (the Receiver).

CAIPR is a national professional association representing receivers, trustees, agents, monitors, and consultants working in the insolvency field. CAIRP is designed to advance the practice of insolvency administration in Canada as well as the public interest in connection with insolvency matters. CAIRP had made submission in the proceedings in the lower court.

Justice Martin held that CAIRP had an interest that would be directly and significantly affected by the outcome of the appeal. He held further that CAIRP – with its expertise in insolvency administration - would bring a broader policy perspective to the appeal that would be helpful to the court, and therefore met the criteria for permission to intervene.

<u>Conditions</u>

As conditions to the leave to participate granted by the ABCA, each intervener is restricted to submitting a factum of no more than 15 pages and oral submissions no longer than 10 minutes.

Further, the Intervener Applicants are not permitted to supplement the record (adduce new evidence) or add new issues to those identified in the ABQB proceedings.

***Enmax Energy Corporation v. Alberta Utilities Commission (*2016 ABCA 276)**

Enmax Energy Corporation ("ENMAX") applied to the ABCA seeking an adjournment to its previous application for permission to appeal AUC Decision 790-D03-2015 (the "Line Loss Module B Decision").

ENMAX had previously applied to the ABCA for permission to appeal the Line Loss Module B Decision, which is one of a series of AUC decisions regarding Milner Power Inc.'s complaint about ISO rules related to line losses (see summary of AUC Decision 790-D04-2016 below for additional details).

ENMAX requested the ABCA adjourn its request to appeal the Line Loss Module B Decision until after the related Module C proceedings are completed.

Milner Power Inc. and ATCO Power Ltd. opposed the adjournment, submitting that the Line Loss Module B Decision is a final standalone decision and not dependant on the outcome of the forthcoming Module C decision(s).

The ABCA granted the adjournment. Martin J.A. held that denying the adjournment could result in litigation by installment, a practice strongly discouraged by the courts. Martin J.A. concluded that there was no compelling reason to make an exception in this case.

ALBERTA ENERGY REGULATOR

Bulletin 2016-20: Fort McMurray Wildfire – AER Recovery Phase Complete
Bulletin – Fort McMurray Wildfires

On July 7, 2016 the AER announced that it had transitioned back to normal regulatory operating procedures following a period of actively monitoring operations in Fort McMurray.

The AER's active monitoring was conducted to ensure that the resumption of oil sands mining and in situ operations – following the unplanned shutdowns necessitated by wildfires in the area – were conducted in accordance with public safety and environmental protection requirements.

In the bulletin, the AER also reminded operators to retain documentation related to the construction of berms and walls undertaken to protect facilities, as such documentation may be requested by the AER.

Bulletin 2016-21: Revision and Clarification on AER's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision
Bulletin – Liability Management Rating – Insolvency – Licensee Obligations

In response to *Redwater Energy Corporation (Re)*, 2016 ABQB 278 (the "Redwater Decision") (discussed above), the AER issued a bulletin regarding interim measures to protect Albertans from additional liabilities resulting from that decision.

In the Redwater Decision, the ABQB held that a receiver and trustee in bankruptcy could renounce and disclaim an insolvent company's non-producing well assets in accordance with *Bankruptcy and Insolvency Act (the "BIA")* section 14.06. The court found that the doctrine of federal paramountcy allows a receiver to write off such assets, notwithstanding an insolvent company's obligations related to abandonment, reclamation, and remediation as a licensee under the *Oil and Gas Conservation Act* ("*OGCA*") and the *Pipeline Act* ("*PA*").

The ABQB also found provincial legislation mandating compliance with AER licensee liability rating (LLR) program and related closure, abandonment, reclamation, and remediation obligations to be inoperative to the extent of conflict with the *BIA*.

<u>Change to LMR Requirements</u>

As a result, in Bulletin 2016-21, the AER states that the liability management rating (LMR) of 1.0 is no longer sufficient to ensure the licensees will be able to meet their obligations throughout the life of a project. Transferees must now demonstrate either:

(a) An LMR of 2.0 or higher; or

(b) Provide evidence that the transferee will be able to meet their obligations with an LMR of less than 2.0.

The AER encourages licensees with transactions in progress to contact the AER to arrange a review of their specific circumstances.

<u>Interim Measures</u>

In the bulletin, the AER notes that it is appealing the Redwater Decision to the ABCA (leave to appeal was granted on June 29, 2016).

Effective immediately, and pending the outcome of the appeal or implementation of appropriate regulatory measures (whichever occurs first), the AER summarised the following three interim measures designed to minimize the risk to Albertans:

1. The AER will consider applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to deny an application or impose terms on approval in appropriate circumstances;
2. For holders of existing but unused licence eligibility approvals, prior to the approval of licence transfer applications, the AER may require additional evidence that there have been no material changes since the licence eligibility approval (including evidence of adequate insurance and evidence that directors/officers and shareholders are substantially the same as when the approval was issued); and
3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require transferees to demonstrate that they have an LMR of 2.0 or higher or other evidence that the transferee will be able to meet its obligations throughout the life of the project with an LMR of less than 2.0.

AER Denies Request for Regulatory Appeal by Samson Cree Nations
Regulatory Appeal – Water Act – Aboriginal Rights

Samson Cree Nation ("Samson Cree") filed five regulatory appeal requests. Each request related to approvals issued by the AER to Encana Corporation ("Encana") for its proposed construction and operation of an integrated water, gas gathering and fuel gas infrastructure as part of its proposed hydraulic fracturing project located about 20 km west of Fox Creek, AB (the "Project").

The AER denied the Samson Cree appeal request on the basis that:

- Samson Cree had not demonstrated that it will be directly and adversely affected, or directly affected (as the test may be), by any of the Project applications;
- For the appeal request regarding a certificate issued to Encana under the *Water Act*, the Samson Cree did not file a statement of concern and is therefore not an "eligible person," and the AER decision to issue the certificate is not an "appealable decision" under the *Responsible Energy Development Act* (*"REDA*"); and
- Samson Cree's request for appeal of the AER's September 26, 2014 approval decision of Encana's fresh water storage reservoir was not filed within the 7 day limitation period and therefore not filed in accordance with AER rules.

The AER cited the ABCA decision in *Dene Tha' First Nation v Alberta (Energy and Utilities Board*, 2005 ABCA 68 ("*Dene"*), where the ABCA discussed the "directly and adversely affected" test in the context of Aboriginal rights. In *Dene,* the court stated at paragraph 14:

> [The Board] is not compelled by this legislation to order intervention and a hearing whenever anyone anywhere in Alberta merely asserts a possible aboriginal treaty or right. Some degree of location or connection between the work proposed and the right asserted is reasonable. What degree of is a question of fact for the Board.

The AER held that the Samson Cree had not established specific locations where its members might be affected, or specific ways in which they might be affected by the Project. The AER noted that the Samson Cree provided extensive submission describing the Samson Cree's treaty and other aboriginal rights, and summarized generally the group's exercise of those rights. However, the AER held that Samson Cree did not provide sufficient detail to establish the requisite degree of location or connection with the Project to demonstrate the potential that Samson Cree members might be affected by the AER decisions.

Bulletin 2016-24: Issuance of Directive 085: Fluid Tailings management for Oil Sands Mining Projects
Bulletin –Tailings Management –Directive 085 – Directive 074

The AER announced the release of *Directive 085: Fluid Tailings Management for Oil Sands Mining Projects* ("Directive 085"). Directive 085 sets out the requirements for managing fluid tailings for oil sands mining projects.

Directive 085 replaces *Directive 074: Tailings Performance Criteria and Requirements for Oil Sand Mining Schemes.*

In the bulletin, the AER summarized some of the important requirements under Directive 085, including requirements:

- that existing operators submit fluid tailing management applications to the AER by November 1, 2016;
- that operators minimize fluid tailings accumulation by ensuring that fluid tailings are treated and reclaimed progressively throughout the life of a project;
- that new fluid tailings be ready to reclaim by ten years after the end of mine life, while legacy tailings must be ready to reclaim by the end of mine life; and
- that operators report annually on the performance of their fluid tailings management plans.

The bulletin also states that the AER will prepare an annual performance report on fluid tailings management.

Directive 085 can be viewed in its entirety on the AER website at www.aer.ca.

Bulletin 2016-25: Second 2016/17 Orphan Fund Levy
Bulletin – Orphan Well Association – Orphan Well Levy

In accordance with Part 11 of the *Oil and Gas Conservation Act*, the AER announced that it prescribed, by regulation, an orphan fund levy in the amount of $15 million.

The Orphan Well Association ("OWA"), Canadian Association of Petroleum Producers ("CAPP"), and Explorers and Producers Association of Canada ("EPAC") had previously approved a $30 million orphan fund levy to fund the OWA budget for its 2016/2017 fiscal year. The approved levy is to be collected through two separate levies. The AER collected the initial $15 million levy in April 2016.

In this bulletin, the AER announced that the second half of the levy will be allocated among licensees and approval holders included in the Licensee Liability Rating ("LLR") and Oilfield Waste Liability ("OWL") programs based on the August 2016 monthly assessment.

Each licensee or approval holder will be invoiced for its proportionate share of the orphan fund levy in accordance with the formula:

Levy = A/B x $15 000 000;

where:

- A is the licensee's or approval holder's deemed liabilities on August 6, 2016 for all facilities included within the LLR and OWL programs; and
- B is the sum of the industry's deemed liabilities for all facilities included within the LLR and OWL programs.

Payment and Appeal Due Dates

Orphan fund levy invoices were e-mailed on or before August 11, 2016. The bulletin states that all orphan fund levy invoices must be paid and payment must be received by the AER by September 12, 2016.

Any appeal of invoiced amounts was to be made in writing by September 12, 2016.

Bulletin 2016-26: Manual 005: Pipeline Inspection Updated
Pipelines – Inspection

On August 18, 2016, the AER announced the release of a new addition of the AER *Manual 005: Pipeline Inspections* (Manual 005).

Revisions from the previous version of Manual 005 include:

- Updates to CSA Z6662 references to align with the latest update in CSA Z662-15; and
- Changes to the descriptions of noncompliance to reflect the minor wording changes in CSA Z662-15.

Manual 005 can be viewed in its entirety on the AER website at www.aer.ca, under Rules and Directives > Manuals.

AER Decision on O'Chiese First Nation Application for Advance Funds – Shell Canada Limited Rocky 7 Pipeline Project
Pipelines –Advance Funds – O'Chiese First Nation

On June 30, 2016, the O'Chiese First Nation (the "OCFN") filed an application with the AER for $572,650 in advance funds.

In its decisions, the AER discussed the purpose of advance funds and the requirements that must be met for a party to be awarded advance funds. Of the $572,650 requested, the AER ordered Shell Canada Ltd. ("Shell") to provide the OCFN $25,000.00 in advance funds.

AER Jurisdiction to Award Advance Funding

Sections 58.1 and 59 of the *Alberta Energy Regulator Rules of Practice* (the "Rules") set out the AER's power to award advance funding (s 59) and the factors it must consider in making its decision (s 58.1).

The AER noted that the purpose of the advance funding provisions in the Rules is to assist a party to participate in a proceeding in circumstances where it requires financial assistance in order to make effective submissions. The AER explained that advances are only provided in exceptional circumstances and that an applicant for advance funding must establish financial need.

Information Requirements

In addition to the requirements set out in s 58.1 of the Rules, the AER detailed the more specific requirements set out in *Directive 031: REDA Energy Cost Claims* ("Directive 031"). The information specified in Directive 031 includes:

- A detailed and itemized budget a participant reasonably and necessarily expects to incur in the presentation of his or her participation;
- If a lawyer, expert, or consultant is a necessary component of participation, a summary of the lawyer's, expert's, or consultant's expertise and detailed description of the work proposed to be done in support of the client's participation; and
- Information addressing the factors listed in section 58.1 of the Rules.

The AER panel held that the information provided by the OCFN was, for the most part, insufficient for the panel to adequately assess the request for advance funds.

The AER held that the information provided did not provide adequate explanation for why 800 hours of legal services were required for the hearing of an application for a 7km pipeline. Additionally, the OCFN application did not provide an explanation of why it needed funds in advance of the hearing taking place.

The AER also noted that the OCFN provided little information about what work the unnamed experts would do, if any. Although the application included the qualification of a named expert, insufficient information was provided for the AER to assess the reasonableness or necessity of the costs attributed to that expert.

Decision

Despite the significant deficiencies in the application for advance funds, the AER panel concluded that the OCFN would make contributions to the hearing and that OCFN had demonstrated some need for advance funds.

Of the $572,650 requested, the AER ordered Shell to provide OCFN $25,000.00 in advance funds. The AER made clear to OCFN that it would be required to provide detailed accounting of how those advance funds were spent in compliance with Directive 031 (the “Cost Application”). The AER ordered OCFN to submit the Cost Application within 30 days following the close of the hearing.

ALBERTA UTILITIES COMMISSION

Direct Energy Regulated Services – 2015 Late Payment Penalty Charge Settlement Agreement (Decision 20732-D01-2016)
Rates –Recovery of Costs – Late Payment Penalty Class Action Defence Costs – Prudent/Reasonable Costs

Following six years of litigation, Direct Energy Regulated Services ("DERS") reached a settlement with certain regulated customers who had brought a class action lawsuit seeking damages related to DERS' late payment penalty ("LPP") charge (the "LPP Class Action").

DERS filed an application with the AUC on August 13, 2015 seeking AUC approval of a rate rider to refund its customers $5,778,000, which represented the customer refund amount under the court approved LPP Class Action settlement agreement.

The Consumers' Coalition of Alberta (the "CAA") made submission to the AUC objecting to DERS' application. The CAA argued that DERS' August 13 application and DERS' forthcoming application – seeking to recover its costs related to defending the LPP Class Action – should be submitted as a single "net application." The AUC agreed and directed DERS to submit a single application that included both the customer refund rate rider request and the request to recover costs related to defending the LPP Class Action.

DERS filed an updated application seeking AUC approval to collect $6,093,175 (the "Net Costs") from its customers as a one-time rate rider. That Net Costs amount represented $13,569,257 in total costs by DERS' related to the LPP Class Action, which included settlement costs, legal defence costs, and other associated costs (the "LPP Class Action Costs"), net the $5,778,000 refund to customers. In addition, DERS identified $1,698,082 in LPP Class Action Costs that had previously been recovered in previous general rate applications, and that amount was not included in the Net Costs. DERS provided a breakdown of the Net Costs, reproduced in the table below.

Table 1: DERS Calculation of Net Costs

Cost Category	Description	Amount
Settlement Costs	Class Counsel	$2,450,000.00
	Experts	$648,000.00
	Refund to Customers	$5,778,000.00
	Total Settlement Costs	**$8,876,000.00**
Defence Costs	External Legal Costs	$3,964,413.44
	Experts	$199,900.00
Carrying Costs		$285,190.15
Total Costs Incurred		**$13,569,257.45**
Other Costs and Adjustment	Refund to Customers	($5,778,000.00)
	Prior Customer Payments	($1,698,082.12)
Net Costs	To be collected from customers	**$6,093,175.33**

Recovery of LPP Class Action Costs

The AUC first considered whether the LPP Class Action Costs are costs eligible for recovery by ratepayers. The AUC considered a number of decisions from the Ontario Energy Board (the "OEB"), where the OEB considered the recoverability of costs incurred by utilities defending similar LPP class actions.

The AUC considered OEB Decision EB2010-295, where the OEB held that a utility's costs associated with defending a similar LPP class action to be prudent and therefore recoverable by utilities from ratepayers. The OEB supported its decision on the basis that:

- Imposition of the LPP was an action undertaken by the utilities to protect the interest of the large majority of ratepayers that pay on time;
- All funds generated by the LPP were for the benefit of ratepayers as a whole and did not go to the utility as a special fund or source of profit; and
- The LPP [in Ontario] was specifically mandated by the relevant regulatory authorities.

In Alberta, the LPP was not mandated by the regulator. Rather, DERS had applied under previous rate applications to adopt the LPP charge. The AUC had approved DERS' LPP as recently as July 2015.

Notwithstanding certain jurisdictional differences in regulatory rules, the AUC noted that the OEB's comments on LPP charges being for the benefit of the majority of ratepayers that pay on time were equally applicable in Alberta as in Ontario.

The AUC went on to consider the history of LPP charges before the Alberta Courts and the AUC. Similar to Ontario, the AUC noted a number of Alberta decisions where costs associated with defending LPP class action lawsuits were held to be recoverable. The AUC noted that the LPP served an important regulatory purpose by encouraging the timely payment of bills.

The AUC rejected the CCA's submissions that in approving the LPP Class Action settlement agreement, the court intended DERS' shareholders, rather than ratepayers, to bear the burden of the settlement costs. In rejecting the CCA argument, the AUC explained that the settlement costs were in connection with DERS' provision of regulated services. The settlement costs in this situation fell properly within the AUC's ratemaking jurisdiction.

Therefore, DERS was permitted to recover the Net Costs from ratepayers, subject to the AUC's determination of the reasonableness and/or prudence of the costs claimed.

<u>Prudence or Reasonableness of Costs</u>

The AUC summarized the recent Supreme Court of Canada ("SCC") decisions in *ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission)*, 2015 SCC 45 ("*ATCO Gas"*) and *Ontario (Energy Board) v Ontario Power Generation,* 2015 SCC 44 ("*OEB v OPG*"), where the SCC provided guidance regarding the role of a tribunal when considering the reasonableness or prudence of a utility's costs.

The AUC summarized the following important SCC holdings from *ATCO Gas* and *OEB v OPG*:

- In the context of utilities regulation, there is no difference between the ordinary meanings of "prudent" and "reasonable" (*ATCO Gas* at para 35);
- Unless expressly provided for in the relevant legislation, there is no presumption of prudence or reasonableness with respect to costs incurred by a utility (i.e. burden of proof is on the utility to establish costs incurred were prudent. *OEB v OPG* at para 79); and
- In the absence of express statutory provisions, a tribunal is free to exercise its expertise and has discretion to consider a variety of analytical tools and methodologies in determining whether costs are prudent (*ATCO Gas* at para 48);
- The SCC left open the question of whether the term "prudently incurred" would impose upon a tribunal a particular "no-hindsight" methodology (i.e. prudence is judged on the basis of the information that was known or should have been known to that utility at the time costs were committed).

<u>Settlement Costs</u>

With this background, the AUC first considered the prudence of the settlement costs portion of the LPP Class Action Costs (see Table 1 above).

For settlement costs, the AUC adopted a "no-hindsight prudence review" test because those costs had been incurred at the time the settlement agreement was entered into. The test assesses the prudence of a utility's costs on the basis of the information that was known or should have been known to that utility at the time settlement costs were committed (e.g. at the time DERS entered into the settlement agreement). The AUC also noted that under such a test, the burden remains with the utility to establish the prudence of costs incurred.

The AUC found that between the information provided by DERS and the information available in court records, there was sufficient information for the AUC to determine the reasonableness of the settlement costs.

The AUC held that entering into the settlement was a reasonable course of action and likely saved ratepayers the costs of continued litigation. The AUC concluded that the settlement costs, as submitted by DERS, were reasonable and therefore recoverable.

<u>Defence Costs</u>

The AUC went on to compile a list of relevant factors to assess the prudence of the defence costs portion of the LPP Class Action Costs.

In addition to the *ATCO Gas* and *OEB v OPG* decisions, the AUC referenced AUC Rule 022, *ATCO Gas and Pipelines Ltd. v Alberta (Utilities Commission)*, 2014 ABCA 397, and *Helm v Toronto Hydro Electric System Limited*, 2012 ONSC 2602, in compiling its list of relevant factors. In determining the prudence of the defence costs, the AUC considered whether:

(a) the amount of the settlement is substantial, particularly having regard to the difficulties associated with recovery of the claim;

(b) the liability was contested and the outcome was difficult to predict;

(c) the work was done at all;

(d) the work done was excessive;

(e) the work was duplicated;

(f) too many people were put to work;

(g) the people chosen to do the work were too expensive;

(h) the charges of those working were too high; and

(i) the work was conducted in an efficient, imaginative and cost-effective manner.

The AUC noted that no assessment of DERS' defence costs was undertaken by the courts or by external audit. Therefore the AUC had only the information provided by DERS to assess the reasonableness of those costs.

With respect to the amount of the settlement being substantial, the AUC noted that the LPP Class Action was ongoing for a long period, and involved many complex legal issues. This weighed in favour of approving DERS' defence costs.

The AUC also held that it was satisfied that the work was done, but noted a number of areas where work might have been duplicated or certain tasks were completed by over-qualified people. The AUC examined legal bills in detail, and concluded that a 25% reduction to the legal fees claimed was warranted. Of the $4,408,067 in defence costs incurred by DERS, the AUC approved $3,306,050 as recoverable from ratepayers.

Method of Recovery

DERS proposed the Net Costs be collected from ratepayers by way of a one-time rate rider. The AUC disagreed with DERS that the proposed rate rider, which resulted in a collection of $8.38 per site, would not constitute a rate shock to its customers. The AUC noted that the proposed rider would result in bills approximately twice as large for the average DERS customer.

To mitigate this potential for shock to some customers, the AUC approved a rate rider over a 6-month collection period.

Additional Comments of Bill Lyttle (AUC Commissioner)

AUC Commission Member Bill Lyttle made additional comments on the difficulties faced by the AUC reconciling the interests of all ratepayers and the class of ratepayers that were plaintiffs as part of the class in the LPP Class Action.

Commissioner Lyttle stated:

> I am sensitive to the plight of DERS' customers especially in these challenging economic times. I find it particularly difficult to explain to ratepayer that parties from both sides had extensive legal and expert costs, and were racking up hourly charges for this account over many years. The plaintiff and defence legal teams were paid significant hourly rates as detailed in the decision. The size of these legal teams were shamefully large and extensive. A change in legislation may be required so that ratepayers are left with the benefit of the settlement but the entirety of the resultant costs should be addressed in some other manner.

ENMAX Power Corporation 2015-2017 Electricity Distribution Performance-Based Regulation Plan – Negotiated Settlement Agreement and Interim X Factor (Decision 21149-D01-2016)

Negotiated Settlement – Rule 018 - Performance Based Regulation – Electricity Distribution

On December 18, 2015, ENMAX Power Corporation ("EPC") filed an application with the AUC for approval of a 2015-2017 performance based regulation ("PBR") plan for its electricity distribution services. After the AUC issued a notice of application, the Consumers' Coalition of Alberta (the "CAA") and the Office of the Utilities Customers Advocate (the "UCA") registered to participate as interveners in the proceeding.

In EPC's application, the X factor component of the PBR plan would be interim in nature. The interim X factor would be used until the AUC determined the final X factor in the ongoing AUC initiated Proceeding 20414. Proceeding 20414 was initiated for the purposes of establishing the parameters for the next generation of PBR plans.

PBR Plan Overview

The PBR framework provides a mechanism to adjust rates annually for each class of ratepayers using the following formula:

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

Where:

- $R_{t\,=}$ upcoming year's rate for each class;
- $BR_{t-1\,=}$ current year's base rate (i.e. excludes rate rider adjustments);
- I = inflation factor ("I Factor");

- X = productivity factor ("X Factor"), which reflects the productivity improvements the utility can expect to achieve during the test period;
- Z = exogenous adjustments ("Z Factor"), which includes 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").

Negotiated Settlement Process

On January 20, 2016, EPC notified the AUC that EPC, the CCA, and the UCA (collectively, the "Negotiating Parties") were willing to explore a negotiated settlement. In March 2016, EPC applied to the AUC for approval to initiate a negotiated settlement process ("NSP"), pursuant to Section 4 of AUC Rule 018: *Rules on Negotiated Settlements* ("Rule 018"). The AUC approved EPC's request to commence the NSP, and set May 16, 2016 as the deadline for EPC to file any resulting agreement between the Negotiating Parties, or advise the AUC the negotiations were unsuccessful.

In its application, EPC listed the following as the issues that would be the subject of negotiation among the Negotiating Parties:

- going-in rates;
- PBR plan term;
- Interim X Factor (to be replaced by a final X Factor to be determined in Proceeding 20414);
- I-X mechanism
- Y Factors;
- Z Factor mechanism; and
- reopeners.

On March 10, 2016, EPC notified the AUC that the Negotiating Parities had reached a negotiated settlement in principle on all the major issues except for the interim X Factor. On May 12, 2016, EPC filed a negotiated settlement application with the AUC. The application included a settlement brief and the terms of the negotiated settlement agreement for EPC's 2015-2017 PBR plan (the "NSA").

Consideration of NSA

The AUC's role in approving negotiated settlements is governed by sections 132 – 135 of the *Electric Utilities Act* (the "*EUA*") and Rule 018. EPC requested the AUC consider the NSA pursuant to Section 135 of the *EUA*, which requires the AUC to either accept or reject a negotiated settlement agreement in its entirety. EPC further requested that if the AUC had concerns with certain NSA provisions, it indicate to the Negotiating Parties those provisions and provide the parties an opportunity to re-negotiate rather than reject the entire NSA. The AUC agreed to consider the NSA on this basis.

After reviewing the relevant legislative provisions, Rule 018, and case law, the AUC summarized the factors it must consider in determining whether to reject or accept the NSA. Those factors are:

- Fairness of the NSP: assessing whether there was procedural fairness, both with respect to adequate notice and with respect to the conduct of the negotiation process itself;
- Just and reasonable rates: the AUC considers the reasonableness of the individual elements of the NSA in accordance with its duty to ensure just and reasonable rates; and
- Patently against the public interest or contrary to law: the AUC considers each of the material provisions of the NSA in determining whether those provisions appear contrary to accepted regulatory practices or are clearly contrary to law.

Fairness of the Negotiated Settlement Process

The AUC noted that the UCA and CCA had been provided sufficient notice to allow them to participate in the negotiations as informed parties. The AUC concluded that from the information submitted by EPC, the AUC was satisfied that the negotiations were conducted in an open and fair manner. The AUC also reviewed the terms of the NSA to ensure customers not directly represented in the negotiations were not compromised.

The AUC concluded that the NSA provides a reasonable balance of customer interests from all rate classes. Based on this review – and the fact that no larger commercial or industrial customers filed submissions in opposition of the NSA – the AUC concluded the negotiated settlement process was fair.

Public Interest

EPC submitted that the proposed PBR plan agreed to under the NSA was consistent with the requirements and directions set out in AUC Decision 2012-237, in which the AUC had previously set out PBR plan parameters for other utilities under the AUC's jurisdiction.

The EPC summarized the terms of the NSA as follows:

- The PBR formula is the same formula previously approved by the AUC in Decision 2012-237. The use of the I Factor methodology, proposed Y Factor, and EPC's line loss reduction program are generally consistent with those previously approved by the AUC for EPC and other distribution utilities.
- The going-in rates for the PBR plan are determined through cost-of-service methodology. The going-in rates under the NSA are the 2014 distribution access service (DAS) rates, adjusted to reflect the revenue shortfall in 2014.
- The 3-year PBR plan term under the NSA aligns with that of other distribution utilities.
- There is no efficiency carry-over mechanism included in the PBR plan.

The AUC noted that the NSA represents a unanimous agreement reached as a result of successful negotiations. The unopposed NSA resulting from the successful efforts of the Negotiating Parties, including the CCA and UCA representing a majority of EPC's customers, supported a finding that the NSA is in the public interest.

The AUC concluded that having considered the NSA in its entirety, approval of the NSA would result in greater regulatory efficiency and cost savings to customers than would a contested process.

However, as noted above, the Negotiating Parties did not reach an agreement with respect to the interim X Factor. The Negotiating Parties requested that the AUC consider their opposing positions and make a determination regarding the interim X Factor.

Interim X Factor

EPC proposed a total factor productivity ("TFP") growth factor of negative 0.89 percent and a stretch factor of 0.0 percent. Both the CCA and UCA proposed a TFP growth factor of 0.96 percent and a stretch factor of 0.20 percent, for an X Factor of 1.16 percent, consistent with the Decision 2012-237.

The AUC noted that any analysis with respect to the TFP growth factor or stretch factor components of the X Factor, even on an interim basis, would be premature and unfair to parties participating in Proceeding 20414. The AUC stated that it was not persuaded by the consumer groups' argument that the 1.16 percent X Factor should be used.

The AUC did not adopt either of the proposed interim X Factors advanced by EPC or the consumer groups. Instead, the AUC ordered the interim X Factor be set at 0.8 percent, as determined in Decision 2009-035.

AltaLink Management Ltd. – South and West of Edmonton Area Transmission Development Cooking Lake, Saunders Lake, Wabamun and Leduc Developments (Decision 20987-D01-2016)
Transmission – Facilities Application — Property Value Impacts

AltaLink Management Ltd. ("AltaLink") applied to the AUC for approval to develop five transmission projects (the "Projects") necessary to reinforce the 138-kilovolt ("kV") and 240-kV transmission system in Leduc, Strathcona, and Parkland County areas, near the City of Edmonton ("Edmonton").

The most significant transmission project was the proposed Cooking Lake transmission project, consisting of 24 kilometres ("km") of new 138-kV transmission line located east of Edmonton (the "Cooking Lake Development"). In its application, AltaLink proposed its preferred route and an alternate route for the Cooking Lake Development. The preferred route was opposed by a group of interveners called the Cooking Lake Opposition Group ("CLOG") and the alternate route was opposed by the Cooking Lake Alternate Route Resistors ("CLARR"), Strathcona County Concerned Residents Group ("SCCR"), and Leduc County.

The AUC approved the Projects, including the Cooking Lake Development, for the reasons summarized below.

AUC Process

As the transmission facility owner for the service area surrounding Edmonton, AltaLink submitted the facility application for the Cooking Lake Development as a project within the AESO's Needs Identification Document Approval U2014-183.

The application was considered in a public hearing in Edmonton. Although AltaLink's application was for the approval of five facilities, the Cooking Lake Development was the primary focus of the hearing (77 of the 79 statements of intent to participate ("SIP") in the proceedings related to the Cooking Lake Development).

Consultation

A number of members of CLOG and CLARR submitted that the consultation program undertaken by AltaLink was inadequate or did not adequately address stakeholders' concerns.

Notwithstanding such concerns, the AUC held that AltaLink began its participant involvement program early in its application development, made efforts to provide potentially affected parties with sufficient information to understand the proposed development and its potential impacts, and provided sufficient opportunity for parties to express their concerns.

The AUC concluded that AltaLink was reasonably responsive to concerns raised by stakeholders and had met the prescribed consultation requirements under AUC Rule 007 and previous AUC decisions.

Expert Evidence on Impact to Property Values

AltaLink, CLOG, and CLARR each hired experts in property valuation to give evidence in the proceedings. AltaLink hired Serecon Inc. ("Serecon"), CLOG hired HarrisonBowker Real Estate Appraisers Ltd. ("HarrisonBowker"), and CLARR hired Gettel Appraisal Ltd. ("Gettel").

The AUC reviewed the evidence of each of these experts. In considering the evidence, the AUC considered not only the experts' conclusions, but assessed each expert's methodology in determining the weight to afford their respective evidence.

The AUC noted that all experts used a two step process to estimate property value impacts for AltaLink's preferred route for the Cooking Lake Development versus alternative routes proposed by the interveners. In the first step, each expert estimated a range of impacts on property values based on in-house comparative analysis, review of third-party property value literature, and personal judgement.

In the first part of its analysis, Serecon used a paired sales analysis ("PSA") methodology to estimate the effects of a 138 kV transmission line on agricultural and residential properties. PSA estimates impact on property value by comparing pairs of sample properties that are similar to the subject property, with the only difference being the existence of a 138 kV high voltage transmission line ("HVTL") near one of the properties in each pair.

In the second part of the analysis, Serecon estimated the impact on property values to properties located on or adjacent to the preferred route and alternative routes for the proposed transmission project. Serecon estimated that approval of the preferred route could negatively impact the value of 14 properties, with estimated impacts between 0 and 14 percent, with an average negative impact of 4 – 6.4 percent on property values. For the alternate route, Serecon estimated that 33 properties could be negatively affected. Serecon estimated negative impacts ranging from 0 to 15 percent, with an average negative impact of

4.5 to 7.4 percent. Serecon concluded that approval of the preferred route would have less overall impact on property values with regard to both the number of affected properties and the average impact to each property.

HarrisonBowker used similar PSA techniques to estimate the impact of HVTL to property values of nearby properties. Gettel relied on case studies to estimate the impact to property value and did not conduct PSA using original data.

The AUC stated that it preferred Serecon's evidence to that of HarrisonBowker and Gettel because Serecon's PSA was the most representative of the actual conditions along the preferred and alternative routes.

For the second part of Serecon's analysis, the AUC noted that Serecon may have underestimated impacts to property values by assuming no impact to properties across the road from a transmission line or vacant properties. However, the AUC accepted Serecon's conclusion that the overall negative impacts of the alternative routes would be greater than the impacts of the preferred route.

The AUC concluded that from the perspective of minimizing negative property value impacts, the preferred route was the superior option.

Impacts on Development and Transportation

CLOGG and CLARR members expressed concerns about the preferred and alternate routes' impact to future development. CLOGG expressed concerns related to the preferred route while CLARR expressed similar concerns regarding the alternate route.

Leduc County's expert, Mr. Preikikasaitis, stated that the preferred route better reflected the policy directions set out in the applicable Alberta land use framework, Capital Region Board plans, and local municipal development plans.

Leduc County also submitted as evidence a report from Mr. Willis of Bunt & Associates regarding the preferred and alternate route's impacts on transportation in the area. Mr. Willis stated that plans for road improvements would necessitate the relocation of 11 km of transmission line, if the alternate route was approved.

The AUC agreed with AltaLink's submissions that the preferred route would result in fewer negative impacts to future development and transportation upgrades and less impact to existing distribution lines. The AUC noted that the costs associated with disturbance to distribution lines are significant and are a cost that is borne by ratepayers.

Approval

The AUC approved the Projects, including the Cooking Lake Development, along the preferred route proposed by AltaLink.

ATCO Electric Ltd. – 2015-2017 Transmission General Rate Application (Decision 20272-D01-2016)
Transmission – General Rate Application – Use of Forecast – Depreciation Parameters

ATCO Electric Ltd. ("ATCO") filed a general rate application with the AUC for the test years 2015, 2015, and 2017 (the "General Rate Application" or "GTA").

The AUC received SIPs from AltaLink Management Ltd. (ALtaLink), Alberta Direct Connect Consumers Association ("ADC"), Industrial Power Consumers Association of Alberta ("IPCAA"), Consumers' Coalition of Alberta ("CCA"), Office of the Utilities Consumer Advocate ("UCA") and the City of Calgary ("Calgary"). The CCA, ADC, and IPCAA also worked together as part of a coalition called the Ratepayer Group ("RPG").

Length of Test Period

The CCA submitted that the AUC should limit the test period to two years due to the risk associated with the current economic uncertainty in Alberta. Similarly, the RPG noted ATCO's history of over-earning in the past 10 years and suggested that including 2017 would provide little or no future benefit to ratepayers.

The AUC noted that the GTA and resulting AUC proceedings had been unusually protracted due to numerous re-filings and other interlocutory steps. While on the one hand the unduly long process had eroded efficiency gains that might have resulted from using a longer test period, these same factors meant that for all of 2015, and much of 2016, actual cost data was available. This mitigated the risk associated with basing rates on forecasts. The AUC also noted that excluding 2017 this late in the process would result in duplication and redundancy when the AUC considered ATCO's next GTA.

The CCA motion was therefore denied, and the AUC approved the use of the three year test period.

Forecasting Methodology and Assumptions

The recent economic downturn in Alberta brought into focus issues regarding the treatment of personnel costs when an employee is terminated in a given year and a regulated entity incurs severance costs.

With respect to personnel costs, the AUC agreed with the RPG's submission that the mid-year convention should be applied with respect to forecasted termination of full time equivalent ("FTE") positions. The effect of the mid-year convention is to deem an employee terminated at the beginning of the year (or anytime, for that matter) as having been terminated at mid-year for the purpose of calculating the revenue requirement in that year. The mid-year convention mitigates a utility's incentive to terminate employee's at the beginning of the year, but still collect from ratepayers the terminated employee's entire year's salary.

The AUC held that "a utility should apply the mid-year convention to the removal of an FTE in the year of its forecasted removal if the utility is not expecting to fill the position going forward."

With respect to severance costs, ATCO submitted that international accounting standards allow severance costs pertaining to capital FTEs be expensed rather than capitalized. The RPG submitted that ATCO had misinterpreted International Accounting Standards (IAS) 16 – Property, Plant and Equipment – and recommended the AUC direct ATCO to capitalize those severances costs.

The AUC concluded that ATCO's interpretation of IASs was reasonable and permitted ATCO to expense, rather than capitalize, severance costs attributable to capital FTEs.

<u>Requested Placeholder Amounts</u>

ATCO requested the AUC approve for placeholder treatment the following categories of costs:

- Common group costs;
- Corporate licence fees;
- IT common matters costs for price only, not volume;
- Transmission line insurance costs;
- Return on equity and common equity ratios; and
- Defined benefit plan pension costs.

The AUC approved ATCO's request for common group costs as filed. ATCO submitted a Common Group Cost Application on June 8, 2016, which was assigned AUC proceeding number 21701.

The AUC denied ATCO's requested placeholder amounts for corporate licence fees. The licence fees were the subject of Proceeding 21029, for which AUC decision 21029-D01-2016 was issued on June 30, 2016 (the "Licence Fees Decision").

In the Licence Fees Decision, the AUC stated that it was not persuaded the licence fees payable by ATCO Electric and ATCO Pipelines to their parent ATCO Ltd. constituted reasonably incurred costs in connection with providing utility services. The licence fees are intended to compensate the parent for its subsidiaries' use of certain intangibles including economies of scale purchasing power benefits, benefits of the ATCO name, intellectual property, and know-how.

Specifically, the AUC was concerned about the ambiguity with respect to the valuation of benefits realized by the subsidiaries as a result of their relationship with their parent. Further, the Commission noted that there had been no effort undertaken by the subsidiaries to critically assess whether the licence fees represented the fair market value of any benefits received.

With respect to requested placeholder for IT common matters prices, the AUC noted that IT prices were being determined in Proceeding 20514 (the "IT Common Matters Proceeding"), but that determining IT volumes was being determined under the current proceeding. Because ATCO had not proposed a place holder for prices, the AUC ordered ATCO to confirm in its compliance filing whether it proposed an IT cost placeholder in relation to the IT Common Matters Proceeding.

ATCO proposed placeholders of 8.30 percent for return on equity and 36.0 percent for the common equity ratio for each of the three test years. The AUC noted that the final approved return on equity and deemed equity ratio for 2013-2015 had been determined in Decision 2191-D01-2015. Therefore the AUC denied the use of a placeholder for the year 2015, but approved the proposed placeholders for 2016 and 2017.

<u>Fuel Costs</u>

ATCO proposed a deferral account for fuel costs due to uncertainty in both fuel prices and volume. ATCO proposed the use of a deferral account on the bases that:

1. Fuel costs volatility can be very high,
2. ATCO has limited ability to control either the price or the volume, the latter of which varies as a result of load variation, and
3. There is no offsetting revenue associated with fuel price or volume changes.

The AUC discussed its reasons in Decision 2013-358, which dealt with the continued use of a deferral account for fuel. In Decision 2013-358, the AUC found that the use of a deferral account for fuel was not warranted as ATCO's fuel costs represented an insignificant proportion of its total revenue requirement (about 1%) and the use of deferral account treatment for fuel costs removes any incentive for ATCO to improve efficiency to minimize such costs.

The AUC was not persuaded by ATCO's proposal to re-establish deferral account treatment for fuel costs.

Operating Costs Forecast Methodology

In Decision 2013-358, the AUC instructed ATCO to develop its forecast from an assumed zero-base, which seeks to reassess costs required to fulfill its statutory duties on an annual basis, as opposed to assuming that costs are simply incremental to the forecasted or actual costs from the preceding year.

ATCO submitted that it employed an activity-based forecasting approach whereby it considered the activities to be performed for each test year, and then evaluated if such costs are indeed required to provide safe and reliable service.

The AUC held that it was satisfied that ATCO's methodology was in accordance with the direction provided by the AUC in Decision 2013-358.

Vegetation Management

RPG submitted that ATCO had not provided a logical explanation to support the significant increase in the proposed ratio of areas treated to areas under vegetation management ("VM") in the test years relative to the 2008 – 2014 period (e.g. the ratio in 2014 was 1.8%, which jumped to 8.6% in 2015, the first test year).

In response, ATCO submitted that its forecasts were based on current conditions, as assessed by professional foresters.

The AUC concluded that a major driver in the increase in actual VM expenditures in 2015 was related to a backlog of deferred work from previous years. In particular, ATCO had experienced issues related to the availability of contractors to complete the forecasted VM work.

The AUC held that customers should not bear a disproportionate share of risk that ATCO, for whatever reason, is unable to complete its forecasted VM work.

The AUC directed ATCO to set up a reserve account for VM in its no cost capital in its revenue requirement schedules. The AUC further directed that ATCO will be required to set off amounts that exceed approved forecasts in a year against amounts included in approved forecasts for subsequent years within the same test period. Approved but unused amounts remaining at the end of the test period are to be added to the VM reserve account for the next GTA period. In other words, ATCO may defer work within the test period, but the total recoverable VM costs cannot exceed the total permitted VM amount in that period.

The AUC also applied a 25% reduction to the 2016 and 2017 VM forecasts submitted by ATCO.

Telecommunication Costs

ATCO proposed to change its method for the allocation of telecommunication network costs. Under its proposal, ATCO Electric Transmission would recover telecommunication costs from ATCO Electric Distribution for the use of the network built by the transmission affiliate.

ATCO submitted that its proposed treatment of telecommunication costs was intended to provide a price signal consistent with competitive markets, to encourage a more efficient outcome with respect to telecommunication cost allocation. ATCO also proposed giving a 10 percent discount to its affiliate for the use of telecommunication network.

The UCA submitted that ATCO Electric Distribution has consistently used its affiliate's telecommunication networks and would continue to do so with the 10 percent discount proposed by ATCO. The UCA also submitted that the different regulatory regimes applicable to the distribution arm (performance based regulation or "PBR") and transmission arm (cost-of-service regulation) would create a situation in which double-recovery of telecommunication cost would occur.

The AUC agreed that the proposed change to the allocation method of telecommunication costs would result in double-recovery at the expense of transmission customers. This is because ATCO Electric Distribution's rates under its existing PBR rates would not change, but the allocation of telecommunication costs would. As a consequence, transmission customers would bear an additional burden caused by ATCO Electric Transmission revenue shortfalls arising from the reallocation of costs.

The AUC denied the proposed telecommunication costs allocation method and directed ATCO to continue to use the allocation percentages approved in its 2013-2014 GTA.

Depreciation Parameters

ATCO filed a depreciation study prepared by Larry Kennedy (Mr. Kennedy) of Gannet Fleming, Canada, ULC ("Gannet Fleming").

In response to ATCO's depreciation study, the CCA filed evidence prepared by Mr. Jacob Pous (Mr. Pous) of Diversified Utility Consultants, Inc., to address a number of issues related to ATCO's requested depreciation provisions, based on Mr. Kennedy's study.

Mr. Pous's most significant critique of Mr. Kennedy's study was the fact the Mr. Kennedy had included forecasted retirements in determining depreciation parameters (i.e. average service life and net salvage estimates). Mr. Pous submitted that Mr. Kennedy's inclusion of forecast data in the development of depreciation parameters is inconsistent with industry practices in the field of depreciation analysis.

The AUC concluded that the use of forecasts has been previously limited strictly for the purpose of developing *depreciation rates* within a depreciation study conducted for the purpose of a GTA. The AUC held that the use of forecast data to develop *depreciation parameters* has not been permitted in the past and that the portions of Mr. Kennedy's study that did so would be afforded little or no weight in the AUC's determination of the reasonableness of ATCO's proposed depreciation parameters.

It followed that the AUC did not accept many of ATCO proposed changes to depreciation parameters. In particular, a number of proposed net salvage value parameters ("NS") were revised significantly by the AUC including:

- The -175% wooden poles NS proposed by ATCO revised to -90%;
- The -200% steel towers NS proposed by ATCO revised to -25%;
- The -40% substation equipment (AC) NS proposed by ATCO revised to -15%; and
- The -40% HVDC conductor towers (new) NS proposed by ATCO revised to -15%.

<u>Capital Expenditures and Additions Forecast</u>

ATCO submitted its forecasted capital expenditures and additions as shown in Table 1 below.

Table 1: ATCO Forecasted Capital Costs

	2015		2016		2017	
	CapEx	Additions	CapEx	Additions	CapEx	Additions
Direct Assigned	246.1	1,999.4	200.4	182.9	272.8	204.1
Capital Maintenance (incl. isolated generation)	101.8	127.7	128.3	145.9	116.8	116.2
Non-direct assigned (excl. isolated generation)	120.7	148.4	158.7	177.5	137.7	137.0
Net salvage		(14.0)		(13.2)		(2.8)
Total	**369.9**	**2,138.3**	**362.9**	**351.4**	**413.6**	**342.2**

<u>Direct Assigned Projects: Capital Expenditures and Additions</u>

Table 2 below provides a summary of significant direct assigned capital expenditures and additions forecast by ATCO, which the AUC denied or directed ATCO to revise.

Table 2: Direct-Assigned Capital Expenditure/ Additions

Project	Test Year			Reasons for Adjustment to ATCO Forecast	AUC Direction
	2015	2016	2017		
	ATCO Forecast Capital Expenditure + Capital Additions (in millions of dollars)				
Arcenciel Synchronous Condenser projects	11.4	-	-	AUC held that there was insufficient information on the record for AUC to determine the reasonable-ness of the forecast costs	Directed ATCO to remove all forecast capital expenditures and additions, and related costs for these projects
Edith Lake to Sarah Lake 144-kV Line Upgrade and Salt Creek 144-240-kV Substation	0.4	-	-		
Livock 144-240-kV Substation	0.2	-	-		

Cold Lake Development, St. Paul Area – Watt Lake and Whitby Lake Substations and Kitscoty Area Development	0.2	-	-		
54904 – Jasper Transmission Interconnection	1.8	7.8	52.1	AUC considered there to be insufficient evidence on the record to support a finding that the project is more likely than not to proceed as currently scheduled.	Directed ATCO to reduce its forecast capital expenditures in 2017 by $9.5M in compliance filing.
55126 – Ells – 9L76/L08 240-kV DC Line	0.2	-	0.8	Project on hold until the AESO completes a review of the need for, and timing of, the project. After the review is complete, it is possible that the project could be cancelled.	Approved the forecast as a placeholder and directed ATCO, in the compliance filing, to provide an update on the project's status and on the forecast capital expenditures, as required and to provide details regarding the work which is forecast to be completed in the test period.
55737 – Thickwood Hills Transmission Development	1.7	28.4	51.4	Forecast partially based on oral hearing on the project being held in June 2016 and approval being issued in October 2016. In fact, hearing is to take place in September 2016.	Directed ATCO to update its forecast in the compliance filing, to align with the PPS estimate for the project, while also accounting for the delay in the facility application proceeding.
5XXX7 – 7L113 Rebuild	-	0.5	4.0	AUC held that single indirect reference to the project in the AESO Long-Term Transmission Plan is insufficient to support a finding that the forecast capital expenditures for this project are reasonable and should be included in revenue requirement	Directed ATCO to remove the forecast capital expenditures for this project, for the purposes of determining revenue requirement, in the compliance filing.
51181 – Carmon Creek Cogen (Customer Project)	5.7	6.7	24.8	The AUC noted that given the depressed economic climate in Alberta, the uncertain future of the associated cogeneration facility, and the fact that customer had already placed the project on hold, completion in the 2017 test period was very unlikely.	Directed ATCO to remove the forecast capital expenditures for the 2017 test year for this project, in its compliance filing.
54020 – Muir Point of Deliver Substation	0.2	2.0	6.2	Insufficient information on the record for AUC to determine the reasonable-ness of the forecast costs	Directed ATCO to reduce forecast costs for 2016 and 2017 to 0.2 for each of those years.
54156 – Aspen 240-kV Line and Substation	-	5.0	30.0	Project delayed and in early stages of execution. Unlikely that it will be completed in the 2017 test period.	Directed ATCO to reduce 2016 and 2017 forecasts by 90%.
56655 AltaGas Kent Generator – Central East	0.6	1.7	25.2	Kent power plant not under construction and granted extension. Not reasonable to expect completion in 2017.	Directed ATCO to remove forecast capital expenditures and additions for the test period.
58965 – Heartland Pump Station	0.2	6.8	24.4	Given current economic conditions and low oil prices, not reasonable to include project.	Directed ATCO to reduce 2016 and 2017 capital expenditures to 0.2 and remove the forecast capital addition in its compliance filing.

<u>Capital Maintenance</u>

ATCO forecast capital expenditures and additions for its transmission capital maintenance ("TCM") program are set out in the table below.

Table 3: ATCO Forecasted TCM Costs

ATCO's TCM Forecast	Test Year			Reasons for Adjustment	AUC Direction
	2015	2016	2017		
Capital Expenditures	101.8	128.3	116.8	ATCO has consistently over forecast TCM costs.	Directed ATCO to revise its TCM forecasts by reducing both expenditures and additions by 25%.
Capital Additions	127.7	145.9	116.6		

The RPG submitted that ATCO had failed to carry out any cost/benefit analysis of alternatives for nearly all the business cases related to TCM projects, contrary to the AUC's direction in Decision 2013-358, which considered ATCO's 2013-2014 GTA. RPG further submitted that ATCO has continuously over forecast its TCM spending by an average of 36% over the past five years. The RPG submitted that for the years 2013 and 2014, ATCO over earned by $6 million as a result of over forecasting capital maintenance additions, an amount which customers are not reimbursed.

The RPG recommended the AUC set a ceiling on capital maintenance spending of $50.9 million per year, which represented the 10 year average of actual spending, adjusted for inflation.

ATCO responded that RPG's recommendation would effectively force ATCO to run the system into the ground before it would be permitted to increase its maintenance expenditures.

The AUC noted that while the RPG's evidence regarding poor forecasting accuracy was concerning, what was even more concerning was the failure of ATCO to demonstrate that it had attempted to improve its forecasting methodology.

The AUC concluded that a 25% reduction in TCM forecasts was warranted. The AUC directed ATCO to provide a revised breakdown of TCM costs in its compliance filing. However, the AUC concluded that given ATCO's large base of ageing assets, adopting the RPG's ceiling proposal would not be appropriate.

Milner Power Inc. – Complaints regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology – Phase 2 Module C – Preliminary Issues (Decision 790-D04-2016)
Line Loss Factor Methodology – ISO Rules – AESO Complaints

On August 17, 2005, Milner Power Inc. ("Milner") first brought a complaint against the AESO under the *Electric Utilities Act* ("*EUA*") section 25(6) (the "Complaint") about ISO Rule 9.2: *Transmission Loss Factors* and Appendix 7: *Transmission Loss Factor Methodology and Assumptions* (collectively, the "Line Loss Rule").

On April 16, 2014, the AUC issued Decision 2014-110, in which the AUC review panel upheld the findings in AUC Decision 2012-104. Specifically, the AUC held that the Line Loss Rules was unjust, unreasonable, unduly preferential, arbitrarily and unjustly discriminatory and inconsistent with and in contravention of the *EUA* and portions of the *Transmission Regulation* dealing with line losses.

On August 8, 2014, the AUC released a list of issues and proceeding schedules directing that Phase 2 of the proceeding be divided into three modules: A, B and C.

Module A would consider several issues of fact, law and jurisdiction; Module B would consider the development of a new line loss factor calculation methodology and line loss rule; and Module C would address the determination of financial compensation that parties were entitled to receive or had to pay, as the case may be.

On April 21, 2016, the AUC issued a ruling regarding the process for determining Module C issues, in which it determined that:

1. It would be premature to determine the proper amount of compensation before the development of a compliant methodology and Line Loss Rule;

2. There are several issues, relevant to Module C, which can be determined in the absence of a new rule (the Phase 2 Module C Preliminary Issues).

On September 18, 2016, the AUC issued Decision 790-D04-2016, which addressed the Phase 2 Module C Preliminary Issues. The AUC's findings with respect to each of those issues are summarized below.

<u>Issue A: Parties Eligible for Compensation</u>

Most parties submitted that all generating units subject to the 2005 Line Loss Rule should be eligible for compensation. ENMAX submitted that only generators that complained about the rule should be eligible, and only eligible from the date they made a complaint.

The AUC held that all ratepayers affected by the unlawful line loss charges should be eligible for compensation. The AUC concluded that the portion of the (unlawful) ISO Tariff based on loss factors was part of a negative disallowance scheme and therefore interim in nature. Any adjustments to bring those rules into compliance will ensure that the final rates are just and reasonable and therefore lawful. The fact that some generators will be worse off under the lawful final rates is not the same thing as punishing those generators, as submitted by ENMAX.

Issue B: Identify and Notify Affected Market Participants

The AUC held that the AESO is in the best position to identify parties affected by the unlawful Line Loss Rule.

With respect to notice, the AUC held that although there had been ample notices issued throughout the history of the Complaint and related proceedings, out of an abundance of caution, it would issue a further notice to past and current market participants. This notice will alert participants of the upcoming adjustments to interim tariff charges since January 1, 2006.

Issue C: Large Charges May Affect Viability

Some parties argued that potentially large charges that could affect the viability of a generator would not be in the public interest and therefore should not be allowed.

The AUC rejected that view, noting that it would not be just and reasonable to allow parties to permanently benefit from unreasonable rates at the expense of injured parties.

The AUC noted that only after charges and credits have been recalculated and incorporated in to the ISO tariff (Module B), will it become apparent if there are any large charges that may compromise the ongoing viability of an existing generator. The AUC also noted that the AESO has considerable leeway to arrange deferred payments in cases where a generator's viability would be affected.

The AUC held that its ultimate determination of Module C has the potential to produce a material adverse effect on some market participants. The AUC stated that if such an impact would compromise the ongoing viability of an existing generator, the AUC could take that into consideration in determining the manner in which line losses costs would be collected.

Issue D: Cost Recovery

The AUC noted that it had previously issued a 2008 bulletin and subsequent 2010 correspondence in which the AUC stated that it would not establish a cost regime in connection with markets proceedings.

The AUC held that such notice was sufficient for parties to be aware, or should reasonably have been aware, that they would not be eligible to recover costs. Generators' decisions to participate or not were therefore made with the knowledge that they would not be able to recover the associated costs. The AUC rejected arguments from some parties that successful parties should receive costs.

Issue E: Interest Costs

The AUC held that the reallocation of the costs of losses only addresses part of the injustice that occurred whereby some parties unjustly paid too much and other parties unjustly paid to little.

The AUC concluded that it is just and reasonable to also consider the time value of money dating back to January 1, 2006, and that awarding (or charging) interest is a reasonable method to do so.

The AUC found that setting the relevant interest rates to the Bank of Canada's Bank Rate plus 1.5% is consistent with the guidance set out in AUC Rule 023 regarding interest.

Issues F & G: Aggregation in Prior Periods & Re-doing Merit Orders

The AUC noted that a compliant line loss rule for the period from January 1, 2006 to the effective date of the new line loss rule did not need to be the same as the new line loss rule going forward.

The AUC noted that any attempt to re-construct past market conditions would be very difficult and time consuming, involve considerable speculation, and be inherently affected by hindsight bias.

The AUC held that it is neither feasible nor reasonable to attempt to look back and accurately model what parties would have done in terms of aggregation of offer blocks since January 1, 2006.

The AUC held that apportionment of loss volumes and costs should instead be based on the actions that caused past volumes and costs. In other words, information about the actual operation of generating facilities should be used as inputs to make such determination.

Issue H: Forecast or Actual Data

Most parties argued that using actual data is preferable to using forecast data. Those parties noted that actual data is less susceptible to speculation and judgement, forecast data is only used as a temporary measure until actual data is available. Actual data will be more accurate and reduce the need for Rider E adjustments. It is not practical to create forecasts for 8,760 merit orders in each year from January 1, 2006.

Milner and ATCO Power argued for the use of forecast data because such data is readily available and that such data is also compatible with the version of the AESO's methodology proposed at the outset of Module B.

The AUC noted the importance of ensuring that initial annual loss factors for each generator, prior to applying any calibration factor, should reflect cost causation as much as possible. The AUC held that using actual data would most closely reflect the actual cost causation.

Issues J & K: The Method for and Timing of Collection/Reimbursement

Without making a final determination on these issues, the AUC noted that there might be merit in limiting the amount reimbursed for a calendar year to the amount collected from generators that underpaid. This would involve a two step process whereby the AESO first collects for a calendar year, and after waiting a reasonable period of time to receive payments, issues reimbursements based on each participant's share of the total credits for that year (i.e. pro-rata allocation).

AUC Direction to the AESO

The AUC directed that the AESO file with the AUC a list that includes the contact information for all parties that received an ISO tariff invoice with a loss factor component since January 1, 2006. The AUC directed the AESO to file that information within one month of the decision. The AESO had to file that list by October 28, 2016.

AUC Bulletin 2016-16: Transmission Rate Treatments to Recover Electric Transmission Related Investments

In January 2013, the AUC initiated a coordinated process to examine alternative approaches to mitigate or smooth the impact on consumers of rate increases, while still ensuring that regulated utilities have an opportunity to earn a fair return on invested capital (the "2013 Transmission Rates Initiative").

On August 25, 2016, the AUC issued Bulletin 2016-16 in which it provided its final determinations regarding the 2013 Transmission Rates Initiative.

Forecast Transmission Additions

The AUC noted that in the AESO's five-year long-term transmission planning report issued in January 2014 the AESO forecast $11.6 billion in transmission capital additions. In November 2015, the AESO issued an update to the five-year long term plan, which included a number of announcements about increasing costs. The AUC noted that the added costs for new transmission projects will result in higher rates for consumers.

Rate Impact of New Transmission on Consumers

The AUC noted that the allocation of new transmission capital costs should be clear, predictable and based on sound principles. The AUC noted that regulatory principles generally require the parties that cause the need for new transmission have to pay the associated costs. Prices should reflect the cost of the transmission services that are being provided.

The AUC noted that in practice, the allocation of new transmission capital costs must also be consistent with governing legislation which may be influenced more by public policy than by economic principles, such as the principle of cost causation. Therefore, principles relied on in past decisions regarding cost allocation are at times in conflict with one another. The AUC must exercise its discretion in determining the relative weight assigned to principles when allocating costs in a manner that is just and reasonable.

Alternative Approaches and Rate Treatments to Mitigate or Smooth Impact on Consumers

During the course of the 2013 Transmission Rates Initiative process, the AUC studied two alternatives to the allocation of transmission costs to mitigate impacts to consumers:

1. A rate cap and deferral account mechanism; and
2. The use of depreciation alternatives to delay capital recovery.

Under the rate cap and deferral account mechanism, the transmission costs included in the ISO tariff would be capped and increased each year by the forecast inflation rate. The difference between capped transmission costs and the actual revenue requirement would accumulate in a deferral account, that would increase by the accrual of carrying costs. Overtime, the transmission rate would be increased as the balance of the deferral account is drawn down.

With respect to depreciation alternatives, the AUC noted that depreciation expenses estimate the cost of the service potential consumed. It follows that, if it is predictable that the net revenue generated by an asset will either increase or decrease over time, an accelerated or decelerated time-based method should be used to approximate the rate at which service potential is actually consumed.

The AUC retained Foster Assoiciates Inc. ("Foster") to examine depreciation alternatives. In its report (the "Foster Depreciation Report"), Foster explained that the "dual objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential." If the revenue generated by an asset is predicted to increase overtime, it is appropriate to use an accelerated time-based method, as opposed to a straight-line method currently used in Alberta. Foster stated that a compound interest method can achieve delayed capital cost recovery, which would be appropriate to better achieve intergenerational equity by increasing depreciation expenses as more customers come onto the system.

Testing the Alternatives

The Office of the Utilities Consumer Advocate ("UCA") agreed to assist with the initiative by working with stakeholders to test the two mitigation alternatives. The UCA engaged EDC Associates Ltd. ("EDC") to assist in running models to test the rate smoothing impact of the proposed alternatives.

Conclusion: No New Policy

In the AUC's report on EDC's analysis, it was estimated that while both alternatives achieved some savings, the savings achieved under both were small.

The AUC concluded that the predicted savings were not sufficiently large to adopt either mitigation proposal as policy.

Rather, the AUC directed that parties wishing to pursue the alternatives examined, or to pursue other alternatives, must bring such proposals forward in either an ISO tariff application, in the case of a rate cap and deferral account mechanism or a similar proposal, or a TFO general tariff application in the case of depreciation alternatives.

NATIONAL ENERGY BOARD

TransCanada PipeLines Limited – Vaughan Mainline Expansion Project Approval (Hearing Order GH-001-2016)
Pipelines – TransCanada – Aboriginal Engagement Process

On November 10, 2015, TransCanada Pipelines Limited ("TCPL") applied to the National Energy Board ("NEB") for approval to construct and operate the Vaughan Mainline Expansion Project (the "Project"). TCPL submitted its application (the "Application") under section 58 of the *National Energy Board Act* (the "*NEBA*"), which allows the NEB to exempt a pipeline application from certain provisions of the *NEBA*. Specifically, TCPL requested the NEB exempt the project from sections 30(1)(a) and 31 of the *NEBA (*certificate requirements).

The NEB issued a Letter Decision on August 4, 2016, in which it issued Order XG-T211-020-2016 approving the Project subject to conditions pursuant to *NEBA* section 58 (the "Order"). The Order also included a sunset clause providing for the Order to expire on July 18, 2018 if construction of the Project has not begun.

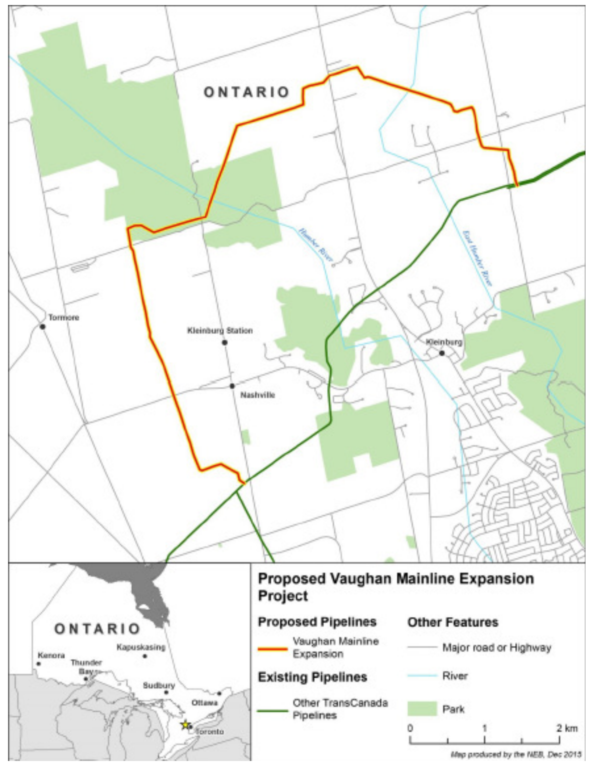
Project Overview

The Project is to be located in the City of Vaughan, in the Regional Municipality of York, Ontario ("Vaughan"). The Project is intended to facilitate access to the growing natural gas supplies in the northeastern United States.

The Project will include the construction and operation of 11.7 km of new buried pipeline (outside diameter of 1067 mm) and associated facilities.

A map of the Project location, submitted by TCPL as part of the Application, is reproduced below.

Figure: Project Location Map



The Project will connect into TCPL's approved King's North Connection project and the existing TransCanada Line 200-2 pipeline. The Project will run north and east before heading south to connect into the existing TransCanada Line 200-3.

NEB Process

After determining the Application was sufficiently complete, on February 10, 2016, the NEB issued Hearing Order GH-001-2016, which established a written and oral process for the NEB's consideration of the Application (the "Hearing Order").

The Hearing Order granted standing upon registration for Aboriginal groups, municipalities, landowners, and occupants that would be directly affected by the NEB's decision on the Application, provided those groups registered before the March 2, 2016 deadline. The Hearing Order also stated that the NEB intended to hold a community meeting where all interveners, commenters, and NGTL would have the opportunity to present oral statements expressing their respective views on the Project (the "Community Meeting").

On March 18, 2016, the NEB released Ruling No. 1 in the proceedings, which established the list of parties (i.e. TCPL and interveners) and the list of commenter's granted standing to participate in the proceedings.

The Community Meeting was held on April 27, 2016. Four interveners and TCPL presented at the Community Meeting.

The NEB held the oral hearing between June 14 and June 16, 2016, in Vaughan, Ontario.

Land Matters and Route Selection

TCPL submitted that it considered many criteria in its route selection process, including utilizing existing linear disturbances, minimizing watercourse and road crossings, avoiding or minimizing impact to environmentally sensitive areas, avoiding lands of certain designated status, input from Aboriginal groups, as well as input from other stakeholders and regulatory agencies (the "Route Selection Factors").

In its submissions, TCPL described seven different route variations for the Project, including alternatives suggested by stakeholders, and provided its rationale for selecting the route described in the Application (the "Proposed Route"). TCPL submitted that, with reference to the Route Selection Factors, the Proposed Route achieved the optimal balance in avoiding or mitigating adverse effects to affected parties and the environment.

The NEB noted that the proposed Project was located in the Greater Toronto Area in close proximity to urban areas where there were many competing interests. The NEB noted that while TCPL had not resolved all routing concerns to the complete satisfaction of certain stakeholders, the NEB was satisfied that TCPL had committed to continued stakeholder engagement and to work with affected parties to resolve outstanding concerns.

The NEB approved the Proposed Route, but ordered that approval be conditional on TCPL meeting various commitments with respect to stakeholder concerns and continued consultation.

Aboriginal Engagement Process

Mississaugas of the New Credit First Nation ("MNCFN"), Haudensaunee Development Institute ("HDI"), and Conseil de la Nation huronne-wendat ("CNH") registered to participate in the proceedings as interveners. All three Aboriginal groups were eligible for pre-decided standing pursuant to the Hearing Order.

TCPL submitted that the Project does not cross any lands defined as reserve lands or lands designated for reserve status under the *Indian Act*. TCPL noted however, that the project does traverse asserted traditional MNCFN territories, Six Nations of the Grand River territories, and is also in the asserted traditional harvesting territory of the Metis Nation of Ontario. However, TCPL submitted that there is no known traditional land use currently practiced in the area.

CNH expressed concerns related to the Project's impact on the extensive Huron-Wendat archeological heritage within the proposed pipeline area. In addition to impacts on identified sites, CNH submitted that there is a strong possibility that additional burial sites would be discovered during construction.

CNH also expressed concerns with respect to current laws regarding archaeological assessments. CNH submitted that ossuaries (burial chambers) can be located at depths starting at 20 to 130 cm, but the required depth for archaeologists conducting an assessment is only 5 cm.

CNH recommended two conditions related to the Project's construction. The first condition is that an archaeologist be present to monitor construction and immediately halt construction upon the discovery of an archaeological site. The second condition is that an Aboriginal monitor from the community be present during construction to both assist the archaeologist in detecting sites and also ensure that they meet their own sacred responsibilities to guard and protect their ancestors.

TCPL submitted in reply that archaeological monitors were not necessary for reasons including that completed archaeological assessments have not yielded any sites of First Nation cultural heritage and that the Project is located primarily on private land that has been previously disturbed.

The NEB held that the project was not likely to result in significant adverse effects on Aboriginal heritage resources. To address the CNH concerns, the NEB imposed a condition on the Project approval requiring TCPL to file a plan for Aboriginal participation in the monitoring of construction activities (the "Aboriginal Engagement Plan"). The NEB stated that it expects TCPL's Aboriginal Engagement Plan to include further opportunity for the CNH to identify additional adverse effects and to address mitigation measures as necessary.

Economic Feasibility

In determining whether to approve a proposed pipeline facility, the NEB considers the need for the proposed facility and the likelihood of it being used at a reasonable level over its economic life.

TCPL submitted the Project will facilitate greater access to the Marcellus and Utica basin (natural gas plays) (the "Plays"), located in the northeast United States and in close proximity to Canadian markets.

Combined, the Plays are estimated to contain between 600 and 700 trillion cubic feet ("Tcf") of recoverable resources. TCPL submitted that production from the Plays is forecasted to grow from 14 billion cubic feet per day ("Bcf/d") in 2014 to 34 Bcf/d by 2025.

No participants made submissions in opposition to TCPL's position regarding adequacy of supply. The NEB held that the natural gas resources contained in the Plays were adequate to support approval of the Project.

With respect to market demand, TCPL submitted that the Project would be supported by existing eastern Canadian markets in Ontario and Quebec. While growth in residential, commercial, and industrial markets was forecasted to be modest, TCPL submitted the Project will be supported by the market's desire for supply diversity and power generation demand, which TCPL stated is forecasted to grow from 0.3Bcf/d in 2014 to 0.7Bcf/d in 2030.

The NEB concluded that there was sufficient market demand to support the Project over its lifetime.

Costs and Financing

TCPL estimated the Project will cost $221 million. The Project will be funded through cash flow from operations and new senior debt. TCPL also stated that it will consider additional funding options including new securities issuances.

TCPL noted that it was not seeking approval relating to the recovery of the Project's cost through tolls.

Approval and Conditions

The NEB issued Order XG-T211-020-2016 approving the Project subject to 19 conditions. The conditions were largely related to TCPL's environmental obligations. Condition 10 also requires TCPL to file with the NEB a plan describing the participation by Aboriginal groups in monitoring activities during the construction for archeological resources.

NOVA Gas Transmission Ltd. – Towerbirch Expansion Project
Pipelines – Tolling Methodology

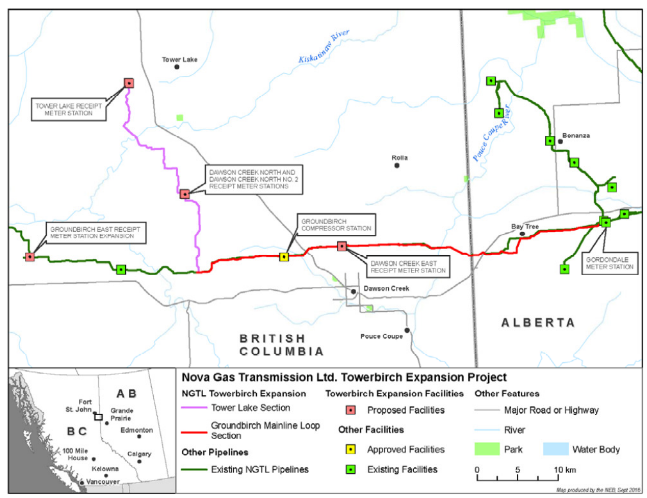
On September 2, 2015, NGTL filed an application with the NEB for approval of 87km of new gas pipeline and associated facilities' in northwest Alberta and northeast British Columbia (the "Project") to connect to the NGTL System.

The Project consists of the Tower Lake Section including 32 km of new NPS 30 pipe (the "TLS") and the Groundbirch Mainline Loop including 55 km of new NPS 36 pipe (the "GBML").

On October 6, 2016, the NEB issued its Report to the Governor in Council ("GIC"), in which it recommended the GIC approve the Project ("the Decision"). In the Decision, the majority of the Board also approved NGTL's proposal to use its current rolled-in tolling methodology for the Project, including the TLS.

The map below shows the proposed route of the Project as recommended for approval by the NEB. The TLS is shown in purple and the GBML is shown in red.

Figure 1: Map Showing Proposed Route of Project



Submission re TLS Tolling Methodology

West Coast Energy Inc. ("WCEI"), WEG, FortisBC Energy Inc., and the Pacific Northwest Group (collectively, the "Opposing Interveners") made submissions opposing NGTL's proposed rolled-in tolling methodology and argued for a stand-alone tolling methodology with respect to the TLS part of the Project.

The Opposing Interveners' arguments included that:

- NGTL's proposed tolling methodology (i.e. rolled-in) would be inconsistent with the principle of cost-causation;
- NGTL's methodology would result in significant cross-subsidization from existing NGTL System shippers and disproportionately benefit new shippers using the TLS facilities;

- The level of integration between the TLS and the NGTL System is not sufficient to support NGTL's proposed rolled-in tolling methodology; and
- Rolled-in cost methodology would provide NGTL with a regulatory (non-competitive) advantage over its competitors, as it allows NGTL to offer tolls for transportation of gas on the TLS well below the actual costs of service for the TLS.

With respect to cost-causation arguments, the cost-causation principle provides that users of a pipeline system should bear the financial responsibility for the costs caused by the transportation of those users' product through the pipeline. The Opposing Interveners argued that the proposed rolled-in methodology would shift all of the costs and risks associated with unused capacity on the TSL to existing users of the NGTL System. The Opposing Interveners argued that such treatment was contrary to the cost causation principle since it was a small group of producers, wishing to access markets serviced by the NGTL System, that were driving the expansion (the "TSL Producers").

The Opposing Interveners submitted that stand-alone tolling for the TLS would adhere to the cost causation principle because the TSL Producers would bear the costs for connecting <u>their</u> gas supply to the NGTL System.

With respect to cross-subsidization, the Opposing Interveners noted that the TSL Producers would only pay in tolls a fraction of the total costs of providing service on the TSL. The remaining costs would be borne by existing shippers, who would receive little benefit from the expansion/extension. The resulting cross-subsidization would conflict with the cost-causation principle.

With respect to integration, the Opposing Interveners argued that the TLS was not an expansion of the NGTL System, but rather, an extension. The Opposing Interveners noted that none of the facilities on the TLS parallel or share the route of the existing NGTL System. The TLS is proposed to connect to a single point at the outer extremities of the NGTL System.

The Opposing Interveners submitted that rolled-in tolls would not be appropriate in such circumstances.

<u>NEB Majority Holdings re Tolling Methodology</u>

The majority of the Board (the "Majority") held that NGTL's proposed rolled-in toll treatment for the TLS to be appropriate in the circumstances.

The Majority defined cross-subsidization as occurring where "revenue from a particular shipper group is insufficient to cover the costs caused by the transportation of their product." The Majority rejected the Opposing Interveners' submissions that cross-subsidization should be examined with respect to the TFS as a stand-alone pipeline, but rather, held that cross-subsidization should be considered in the context of the entire NGTL system.

The Majority held that the TLS facilities are fully physically and operationally integrated into the NGTL System, offering similar nature of service to all other lateral supply pipelines connecting to the NGTL System.

With respect to whether the TSL Producers or aggregate demand of all shippers caused the need for expansion, the Majority found that all NGTL System shippers contributed to the need for expansion. On this point, the Majority noted that:

- Annual well production decrease at 18% a year, meaning existing demand of all NGTL System shippers necessitates continued expansion;
- Access to competitive supply sources (such as the Montney play) is crucial to the participants in the Western Canadian Sedimentary Basin, both producers and purchasers, in light of ongoing natural decline in supply; and therefore
- All NGTL users, not just specific shippers utilizing the TSL facilities, benefit from the development of the economically viable resources to which the TSL facilitates access.

The Majority also supported its findings with reference to the principles of "no acquired rights" and "no unjust discrimination." The Majority held that a departure from the rolled-in tolls would confer acquired rights to existing shippers, because those shippers would receive benefits from the expansion without incurring any additional costs. Further, if the NEB departed from rolled-in tolls with respect to the TSL, TSL shippers would be unjustly discriminated against relative to other lateral line shippers subject to rolled-in tolls.

The Majority was not persuaded by WCEI and other Opposing Intervener's arguments related to the anticompetitive effect of rolled-in tariffs. The Majority noted that:

1. The Project provides necessary additional infrastructure in the area, and that the TLS is not duplicative;

2. There was insufficient evidence to conclude the Project would have significant off-loading effects on WCEI's competing infrastructure;

3. The net economic effect would be positive in light of the cost-efficiency of extracting resources from the Montney play; and

4. The Project will provide providers in the area with additional capacity and choice in choosing where to ship.

Dissent of NEB Member Parrish

Mr. Parrish disagreed with the Majority, and held that rolled-in tolling "will not result in economic efficiency or allow for competitive outcomes in the development of the Tower Lake area."

Mr. Parrish agreed with the Opposing Interveners that rolled-in tariff methodology provided NGTL with a regulatory advantage over its competitors. Mr. Parrish would have ordered NGTL to re-apply for an alternative tolling methodology that respects both the user-pay principle [i.e. cost-causation] and allows for fair competition to access supply and the NGTL System.

Mr. Parrish noted that by NGTL's logic, competitors that connect to the NGTL System could also be considered operationally integrated with the NGTL System. However, those competitors cannot offer service under NGTL's Tariff and therefore cannot be considered commercially integrated. Mr. Parrish concluded that the fact service will be offered under the NGTL Tariff should not be determinative of whether proposed facilities are integrated with the NGTL System.

Comprehensive Review of Tolling in Northeast BC

Some of the Opposing Interveners supported the NEB initiating an inquiry to examine the appropriate tolling methodology for Northeastern BC.

The NEB concluded that determining the need for such a proceeding was outside the scope of the current proceeding considering NGTL's Project application.

However, the NEB did not reject that there may be need for such a review of tolling methodology in the future. Rather, the NEB declined to make any determination on the issue given that many potentially affected parties did not participate in the proceeding that was currently before the Board. This part of the Decision was made on the basis of administrative law principles of natural justice rather than the substantive need for a review of tolling methodology.