ISSUE:
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DECISIONS

REGULATORY
LAW CHAMBERS

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

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

IN THIS ISSUE:

SUPREME COURT OF CANADA

O'Chiese First Nation v Alberta Energy Regulator, et al., 2016 CanLII 32302
Leave to Appeal

The Supreme Court of Canada dismissed the application of the O'Chiese First Nation for leave to appeal the judgment of the Alberta Court of Appeal in *O'Chiese First Nation v Alberta Energy Regulator*, 2015 ABCA 348.

Per its usual practice, the Supreme Court of Canada did not provide its reasons for dismissing the leave to appeal application.

FEDERAL COURT OF APPEAL

Gitxaala Nation v Canada, 2016 FCA 187
Duty to Consult – Order in Council – Facilities – Pipeline

The Federal Court of Appeal ("FCA") received nine applications for judicial review of Order in Council ("OIC") P.C. 2014-809. The OIC ordered the NEB to issue two certificates of Public Convenience and Necessity on specific conditions for the Northern Gateway Project proposed by Northern Gateway Pipelines Inc. and Northern Gateway Pipelines Limited Partnership (collectively, "Northern Gateway"). Northern Gateway would transport oil and condensate from Bruderheim, Alberta to Kitimat, British Columbia. Included in the FCA's consideration of the applications were five applications for judicial review of the Joint Review Panel's (the "JRP") report recommending approval of Northern Gateway, acting under the *National Energy Board Act* and the *Canadian Environment Assessment Act, 2012.*

The Gitxaala Nation, Gitga'at First Nation, Haisla Nation, the Council of the Haida Nation, the Katasoo Xai'Xais Band Council, the Heiltsuk Tribal Council, the Nadleh Whut-en Band, and the Nak'azkli Whut'en Band (the "OIC Appellants") appealed the OIC on the basis that the Crown in Right of Canada ("Canada") had not discharged its duty to consult with Aboriginal groups.

UNIFOR, ForestEthics Advocacy Association, Living Oceans Society, Raincoast Conservation Foundation and the Federation of British Columbia Naturalists (the "JRP Appellants") appealed on the basis that the JRP's conclusions were unreasonable or incorrect.

The FCA summarized Canada's consultation process as follows:

- Phase I: Preliminary Phase. Consisting of consultation on the draft JRP agreement and information would be provided to Aboriginal Groups on the mandates of the National Energy Board and the Canadian Environmental Agency and the Joint Review Panel process
- Phase II: Pre-hearing Phase. Information would be given to Aboriginal groups concerning the JRP process
- Phase III: The Hearing Phase. During this time, the JRP would hold its hearings. Aboriginal groups would be encouraged to participate and to provide information to help the Joint Review Panel in its process and deliberations.
- Phase IV: The Post-Report Phase. Following the release of the Report of the JRP, the Crown was to engage in consultation concerning the Report and on any project-related concerns that were outside of the JRP's mandate.
- Phase V: The Regulatory/Permitting Phase. During this phase, further consultation was contemplated concerning permits and authorizations to be granted for the Project, if approved.

The FCA concluded that the OIC was acceptable and defensible on the facts and law, and was therefore reasonable, being within the wide margin of discretion afforded to the Governor in Council. However, the FCA held that the Governor in Council could not make the OIC unless Canada had also fulfilled its duty to consult with Aboriginal peoples.

The FCA noted that in February 2009, the JRP accepted submissions and public comments from Aboriginal groups, and discussed how consultation would be carried out. The FCA noted that the Gitga'at, Gitxaala and Haisla each met with Canada at this time. The result of this process was that Canada would engage in a "whole of government" approach to Aboriginal consultation and engagement, including reliance where possible on the consultation efforts of Northern Gateway and the JRP itself.

In 2010, the JRP issued procedural directions seeking comment from the public, including Aboriginal groups, concerning a draft list of issues. This culminated in the hearing order from the JRP, which gave notice that hearings would commence in January 2012.

At that time, the FCA noted, Canada consulted with representatives of some of the OIC Appellants. Most of the OIC Appellants also intervened in the proceedings before the JRP, along with Natural Resources Canada, Aboriginal Affairs and Northern Development Canada, Fisheries and Oceans Canada, the Canadian Coast Guard, Transport Canada, and Environment Canada.

The Canadian Environmental Assessment Agency also provided funding to public and Aboriginal groups to facilitate their participation in both the JRP process and consultation with Canada.

It was at this time, the FCA noted, that the *Jobs, Growth and Long-Term Prosperity Act* came into force, repealing the 1992 version of the *Canadian Environmental Assessment Act*. Proceeding under the amended legislation, the JRP had two main tasks: to provide a report pursuant to section 52 of the *National Energy Board Act*; and to include recommendations flowing from the environmental assessment conducted under the *Canadian Environment Assessment Act, 2012*, section 29(1).

The JRP held its hearings from September 2012 through to June 2013, where parties asked questions and filed arguments.

The FCA found that overall, the parties had ample opportunities to participate in the JRP process, and generally availed themselves of that opportunity.

The JRP released its report on December 19, 2013, finding that Northern Gateway was in the public interest, and recommended that the applied-for certificates be issued subject to 209 conditions. The conditions included ongoing and enduring opportunities for affected Aboriginal groups to have input into the planning construction and operation of Northern Gateway through various programs and benefits. The JRP recommended to the Governor in Council that:

- potential adverse environmental effects from Northern Gateway alone are not likely to be significant;
- adverse effects of the Project, in combination with effects of past, present and reasonably foreseeable activities or actions are likely to be significant for certain woodland caribou herds and grizzly bear populations; and
- the significant adverse cumulative effects in relation to the caribou and grizzly bear populations are justified in the circumstances.

Following the release of the JRP's report, Phase IV of the consultation framework took place. This was the main focus of the FCA's review of the consultation process.

Canada began Phase IV by sending letters to Aboriginal groups, seeking input on how the JRP's recommendations and conclusions addressed their concerns. Canada also met with representatives from Aboriginal groups to discuss their concerns. Following these meetings, Canada issued the *Report on Aboriginal Consultation Associated with the Environmental Assessment*.

On June 17, 2014 the OIC was issued, and later published in the Canada Gazette on June 28, 2014. In July 2014, Canada wrote to a number of Aboriginal groups, offering explanations for certain comments made and explaining the OIC itself.

<u>Approach to Judicial Review</u>

The FCA outlined its approach to the judicial review sought in this case by dealing with preliminary issues, determining the standard of review, assessing the administrative decision against the standard of review to see if the FCA should interfere, and if so, what the appropriate remedy is.

<u>Legislative Scheme</u>

The FCA found that this was the first case to consider the legislative schemes of the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* paired with the substantial decision making by the Governor in Council. Accordingly, the FCA held that cases considering other legislative schemes were not relevant to its analysis.

The FCA summarized the legislative scheme broadly speaking in the following manner:

- the proponent of a project applies for a certificate approving the project;
- In response, an environmental assessment is conducted and recommendations are prepared and presented to the Governor in Council in a report; and
- From this information, the Governor in Council decides whether the certification should or should not be issued.

In this specific circumstance, there were two stages in the decision making process: a report stage and a decision stage.

In the report stage, the report of the JRP included an environmental assessment prepared in fulfillment of the requirements of the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012*. The report stage set out a recommendation as to whether the certificates sought by the applicant should be granted and, if so, on what conditions. The FCA noted that, once made, the report is final and conclusive subject only to section 53 and 54 of the *National Energy Board Act* which empower the Governor in Council to consider the report and decide what to do with it.

Notably, the environmental assessment itself is not submitted to the Governor in Council, only the report of it with recommendations concerning its subject matter.

Once the report is completed with recommendations, the FCA explained that the Governor in Council has three options to dispose of the report:

- It can "direct the Board to issue a certificate in respect of the pipeline or any part of it and to make the certificate subject to the terms and conditions set out in the report" pursuant to section 54(1)(*a*) of the *National Energy Board Act*. If this option is pursued, the Board has no discretion. It must grant the certificates within seven days. As part of its consideration, the Governor in Council is obligated to consider whether adverse environmental effects will occur and whether such effects may be justified, and may further impose conditions that must be complied with through a "decision statement" it can cause the Board to issue. The NEB must thereafter issue the decision statement (which forms part of the certificate) within seven days.

- It can "direct the Board to dismiss the application for a certificate" pursuant to section 54(1)(*b*) of the *National Energy Board Act*. If this option is pursued, the NEB must dismiss the certificates within seven days.
- It can remit the matter to the NEB to reconsider its recommendations or terms and conditions, and within a specific time limit if need be. After reconsideration the NEB re-submits its report, and the Governor in Council decides again among these three options.

The FCA dismissed the applications for judicial review of the JRP report, holding that the report itself was not a "decision" under the legislative scheme, and that any deficiency in the report was to be considered solely by the Governor in Council, not the Courts.

In a similar vein, the FCA held that the NEB does not make any real decisions under the legislative framework, holding that the NEB is directed to issue the certificates, either with or without a decision statement, and has no real discretion to exercise after the Governor in Council has rendered its decision. The NEB simply does what the Governor in Council directs.

In the FCA's determination then, the primary attack must be against the Governor in Council's OIC, as the issuance of the certificates follows automatically from the OIC.

Standard of Review

Many of the appellants argued that the relevant standard of review had already been established in *Council of the Innu of Ekuanitshit v. Canada (Attorney General)*, where the FCA determined that a failure to follow processes under the *Canadian Environmental Assessment Act* could invalidate the relevant OIC.

However, the FCA dismissed this argument on the grounds that the decision of the Governor in Council in that instance was reviewing a decision made by others based on an environmental assessment. The FCA held instead that the decision of the Governor in Council balanced a broad variety of matters, including matters that fall within the role of the executive in government. The FCA held that executive authority is vested in the Crown, which is also subject to the duty to consult Aboriginal peoples.

The FCA noted that the factors that the Governor in Council may take into account are so broadly worded that they may include "literally anything relevant to the public interest." Accordingly, the FCA held that given the very broad margin of appreciation and discretion afforded to the Governor in Council in rendering its decision, the decision would be reviewed on a standard of reasonableness – that is, whether the decision falls within a range of acceptable and defensible decisions on the facts and the law.

Review of the Decision

The FCA held that the OIC was reasonable on the basis of the facts and law before it. The FCA found that the Governor in Council was entitled to assess the sufficiency of the information and balance the economic, cultural, environmental and other considerations in coming to its conclusions. The FCA determined that, to rule otherwise would be to second guess the Governor in Council's appreciation of the facts, its choice of policy, weighting of competing public interest considerations, and its access to scientific expertise. The FCA found that these matters were outside of the purview of the courts.

However, the FCA also held that Canada owes a duty of consultation to Aboriginal peoples concerning Northern Gateway, and that if that duty were unfulfilled, that the OIC could not stand. All of the parties to the action conceded on this point.

Duty of Consultation

Following on principles of statutory interpretation, the FCA held that although the *National Energy Board Act* does not list the duty to consult among the factors to be considered by the Governor in Council, such silence cannot be intended to oust the duty to consult. The FCA found that Parliament is presumed to wish its legislation to be valid, and does not intend any absurd, inequitable or unconstitutional results.

The FCA explained that the duty to consult arises when the Crown has actual or constructive knowledge that Aboriginal rights or title may be adversely affected by some act. This duty, according to the FCA, is ground in the honour of the Crown, and the extent of the duty is commensurate with the strength of the claim or rights being asserted and the seriousness of potential impacts. The FCA explained that consultation requirements are essentially a spectrum, citing that a weak Aboriginal interest or minor infringement might only attract a requirement to give notice. In contrast, where the potential infringement is of high significance, and the risk of non-compensable damage is high, a deep consultative process is required. Such a consultation process might require an opportunity to make submissions, participation in the formal decision making process, or an entitlement to reasons showing how Aboriginal concerns were considered and factored in the ultimate decision.

The FCA explained that the Crown may rely on a regulatory or environmental process to fulfill the duty to consult. However, the FCA also pointed out that the consultation process did not dictate a particular substantive outcome, nor did the consultation process equate to a duty to agree.

The standard to which Canada was held, in the determination of the FCA, was not perfection in fulfilling its duty to consult, but rather reasonableness. Accordingly, the FCA stated the relevant test as whether reasonable efforts to inform and consult were made.

However, even on this standard, the FCA held that Canada fell well short of the mark.

In respect of the consultative process, Canada submitted that it consulted using its five phase process, through:

- Direct engagement by Canada with affected Aboriginal groups, both before and after the Joint Review Panel process.
- Participation by Canada in the JRP process in order to effectively and meaningfully:
    - gather, distribute and assess information concerning the Project's potential adverse impacts on Aboriginal rights and interests;
    - address adverse impacts to Aboriginal rights and interests by assessing potential environmental effects and identifying mitigation and avoidance measures; and
    - ensure, to the extent possible, that specific Aboriginal concerns were heard and, where appropriate, accommodated.
- The provision of almost $4,000,000 in participant funding by Canada to 46 Aboriginal groups to assist their involvement in the Joint Review Panel process and related Crown consultations.
- The provision of written reasons to Aboriginal groups explaining how their concerns were considered and addressed.

The OIC Appellants alleged a number of following flaws with Canada's consultation process, a number of which are examined in the following subheadings.

<u>The Governor in Council prejudged the approval of Northern Gateway</u>

The Gitxaala submitted that statements by the Minister of Natural Resources made in the Globe and Mail on July of 2011, wherein he stated that Northern Gateway "is in the national interest" was evidence of bias which prejudged the approval of Northern Gateway.

The FCA did not accept this statement as evidence of bias, as a comment by one Minister made several years prior to the final decision was insufficient to establish a prejudgment of the outcome. The FCA held that the decision maker in this case was the Governor in Council, and that the approval of Northern Gateway was not a judicial or quasi-judicial decision. Accordingly, the duty of impartiality was not co-extensive with that imposed on judicial or quasi-judicial decision-makers.

<u>Canada's consultation framework was unilaterally imposed on the First Nations; there was no consultation on it</u>

The Haisla Nation argued that while it was given opportunity to comment on the JRP process, it was not consulted on the Crown consultation process itself. Numerous other OIC Appellants made similar submissions about the five phase review process.

The FCA held that as a matter of law, the Crown holds discretion as to how it structures the consultation process and how the duty to consult is met. The FCA also noted that Canada significantly changed aspects of the JRP process in response to consultation efforts with Aboriginal groups, and provided ample opportunity for participation.

Accordingly, the FCA dismissed this alleged flaw in the consultation process, holding that Canada's efforts were reasonable.

<u>The consultation process was over-delegated: the JRP was not a legitimate forum for consultation and it did not allow for discussions between Canada and affected First Nations</u>

The Haisla asserted that consultation was a two-way dialogue, and that the JRP process, as a quasi-judicial forum, was inappropriate for use as a tool of direct consultation and engagement.

The FCA held that reliance on an administrative or regulatory tribunal can fulfill Canada's duty to consult. However, the FCA held that because Canada planned further consultations beyond the FCA process, Canada had not inappropriately delegated or relied on the JRP process to fulfill its duty to consult.

Accordingly, the FCA dismissed this alleged flaw in the consultation process, holding that Canada's efforts were reasonable.

Canada either failed to conduct or failed to share its assessment of the strength of the First Nations' claims to Aboriginal rights or title

The Gitxaala argued that, despite repeated requests, Canada did not assess the strength of their claims to governance and title rights during the consultation, not did the Gitxaala receive Canada's assessment of the strength of its claims. Several other OIC Appellants made similar supporting submissions.

The Haisla pointed to a letter from Canada which stated that "the federal government is currently updating its strength of claim and depth of consultation assessment and will provide a description of this analysis to the Haisla Nation once this work is completed and ready to be released." The Haisla submitted that it never received such an analysis from Canada.

The FCA determined that Canada did not, in fact make a commitment to provide its actual legal analysis of the strength of claim. Rather, in the FCA's determination, Canada committed to providing a description of the analysis as an informational component. The FCA further held that the Haisla were provided with a preliminary strength of claim assessment which supported the Haisla Nation, in Canada's view, as having a strong prima facie claim to both Aboriginal rights and title within the lands claimed as part of its traditional territory.

Accordingly, the FCA rejected the assertion that Canada failed to assess the strength of the Aboriginal groups' claims to rights and title. Furthermore, the FCA held that Canada was not obliged to share its legal assessment of the strength of claim, holding that such information is subject to solicitor-client privilege.

The FCA however, reiterated that the strength of claim is a critical component to the content of the duty to consult. As such, Canada must disclose information on this, but was not obligated to share its legal analysis.

The Crown consultation did not reflect the terms, spirit and intent of certain agreements between Canada and the Haida

The Haida submitted that they had entered into five separate agreements with Canada which in their submission reinforced and individualized Canada's obligation to engage in a deep and specific level of consultation. However, the Haida submitted that Canada engaged in only a generic consultation process.

The FCA determined that Canada correctly acknowledged its obligation of deep consultation with the Haida, but rejected the assertion that entering into agreements modified or added to that obligation in any sense.

Remaining flaws in the consultation process

The remaining alleged flaws of the consultative process were viewed by the FCA as interrelated, and were therefore considered together. The grounds are as follows:

- The Report of the JRP left too many issues affecting Aboriginal groups to be decided after Northern Gateway was approved;
- The consultation process was too generic. Canada and the JRP looked at Aboriginal Groups as a whole and failed to address adequately the specific concerns of particular Aboriginal groups;
- After the Report of the JRP was finalized, Canada failed to consult adequately with Aboriginal Groups about their concerns; it also failed to give reasons showing that Canada considered and factored them into the Governor in Council's decision to approve Northern Gateway; and
- Canada did not assess or discuss Aboriginal groups' title or governance rights, nor was the impact on those rights factored into the Governor in Council's decision to approve Northern Gateway.

The FCA noted that the above four flaws were to be addressed under an assessment of Canada's Phase IV of its consultation plan. The FCA ultimately held that this portion of the process was unacceptably flawed and fell well short of the mark, and further failed to maintain the honour of the Crown.

The common thread for Canada's part must be, in the FCA's determination, the intention of substantially addressing Aboriginal concerns as they are raised. The FCA stated the controlling question in this instance as being "what is required to maintain the honour of the Crown and to effect reconciliation between the Crown and the Aboriginal peoples with respect to the interests at stake."

The Kitasoo and Heiltsuk submitted that deep consultation must lead to a demonstrably serious consideration of accommodation, manifested by the Crown's consultation-related duty to provide reasons.

Accordingly, where Canada knew or ought to have known that its conduct might adversely affect each Aboriginal group's rights and title, each group was therefore entitled to consultation based on the circumstances and facts specific to it.

Phase IV of the consultation framework was described as very important in the overall consultation framework by the FCA. And while the JRP report provided specific evaluations on a great number of matters, each evaluation called for a specific response and due consideration by Canada. The FCA noted that the JRP report also did not cover all of the subject matter on which consultation was required.

The FCA noted that Northern Gateway itself made no assessment of its impact on Aboriginal title, confining its assessment instead on the impact of Northern Gateway on rights to harvest and use land and resources in a general sense (although the FCA made clear that Northern Gateway met and continues to meet and consult with affected Aboriginal groups.) The FCA also noted that the JRP made no determination regarding the strength of any Aboriginal group's claim to Aboriginal right or title.

The FCA noted that Canada allotted 45 days to meet with all affected Aboriginal groups, and that Aboriginal groups were given 45 days to advise Canada in writing of their concerns by responding to three questions:

- Does the Panel Report appropriately characterize the concerns you raised during the Joint Review Panel process?
- Do the recommendations and conditions in the Panel Report address some/all of your concerns?
- Are there any "outstanding" concerns that are not addressed in the Panel Report? If so, do you have recommendations (i.e., proposed accommodation measures) on how to address them?

The FCA further noted that Canada requested that responses to the above three questions not exceed 2-3 pages in length, and had to be received prior to April 16, 2014. The FCA noted that representatives for Canada also informed Aboriginal groups of the following constraints on the consultative process:

- Canada's representatives were working on the assumption that the Governor in Council needed to make the decision by June 17, 2014;
- Canada's representatives were tasked with information gathering, so that their goal was to get the best information to the decision-makers;
- Canada's representatives were not authorized to make decisions; and
- Canada's representatives were required to complete the Crown Consultation Report by April 16, 2014.

The OIC Appellants argued that the timelines set by Canada were arbitrarily short and were insufficient in providing for a meaningful consultation. The OIC appellants submitted that they had asked for a deferral on the decision on Northern Gateway.

The FCA noted that while the Governor in Council was subject to a deadline pursuant to section 54(3) of the *National Energy Board Act*, the Governor in Council was able to extend the deadline at its discretion. The FCA found that there was no evidence that Canada gave any thought to asking for an extension from the Governor in Council.

The OIC Appellants submitted evidence of testimony from Canada's representatives in the consultation that many items and concerns raised by, for example, the Haisla, were not addressed in consultation meetings. The Kitasoo also submitted evidence that Canada provided inaccurate information to the Governor in Council, and that Canada failed to correct the inaccuracies after the Kitasoo had requested that such information be corrected. The Heiltsuk, Nadleh and Nak'axzkli also submitted that the Governor in Council did not have sufficient information to make a decision, submitting that the lack of discussion or response on key concerns and impacts regarding the risks of oil spills rendered the information before the Governor in Council prior to rendering a decision insufficient.

Canada submitted that it sent two letters to affected Aboriginal groups on June 9, 2014 and July 14, 2014, and relied on the content of these letters as evidence that it had discharged its duty to consult.

However, the FCA found that the letters could, at best, be characterized as "summarizing at a high level of generality the nature of some of the concerns expressed" by the affected Aboriginal groups. The FCA noted that the letters did not set out which specific concerns were raised, nor what any specific mitigation measures, if any, would be.

The FCA held that the short timelines were not dispositive of a failure to consult properly. However, the FCA determined that the confined role of Canada's representatives, combined with the short timelines, resulted in Canada's conduct falling well short of the conduct necessary to meet the duty to consult. The FCA noted a large number of instances where Canada either failed to respond to concerns raised by Aboriginal groups, failed to provide a suggestion as to how any impacts may be avoided or accommodated, or where Canada simply failed to discuss the subject at all with affected Aboriginal groups. The FCA also held that the July 14, 2014 letter could not be considered to contribute to fulfilling Canada's duty to consult, as the decision to approve Northern Gateway had occurred prior to the transmission of this letter, and any consultation must be completed prior to a decision being made.

Based on the above, the FCA held that Canada failed in Phase IV to engage, dialogue and grapple with the concerns raised in good faith by the Aboriginal Groups and the OIC Appellants. The FCA found that there was no indication of an intention to amend or supplement the conditions imposed by the JRP, to correct any errors or omissions in its report, or to provide meaningful feedback in response to concerns raised.

As a result, the FCA held that a real and sustained effort to pursue meaningful two-way dialogue was missing, noting also that Canada failed to disclose necessary information it had about the strength of claims to rights and title claimed by various Aboriginal groups.

While the FCA pointed out that the duty to consult is not co-extensive with a duty to determine unresolved claims, providing such information strongly informs the level and depth of consultation. The FCA stated that case law made clear that when acting under the duty to consult, Canada must "dialogue concerning the impacts that the proposed project will have on affected First Nations and to communicate its findings." However, the FCA held that Canada repeatedly told Aboriginal groups that it would not share a matter fundamental to identifying any of the relevant impacts; that being information on Canada's assessment of the strength of such claims to rights and title.

Disposition

The FCA accordingly quashed the OIC, rendering the NEB's Certificates OC-060 and OC-061 a nullity.

The FCA ordered that the matter be remitted to the Governor in Council for a redetermination. The FCA ordered that if the Governor in Council wished to reconsider the matter further, that Phase IV consultation be redone promptly with a view to fulfilling the duty to consult with Aboriginal peoples in accordance with the FCA's determinations herein.

ALBERTA ENERGY REGULATOR

Bulletin 2016-16: Licensee Eligibility – Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision
Bulletin – Licensee Liability – Abandonment – Bankruptcy

The AER made this announcement in response to the Alberta Court of Queen's Bench decision in *Redwater Energy Corporation (Re)*, 2016 ABQB 278. That decision involved a dispute between the receiver of Redwater Energy Corporation, the Alberta Treasury Branches, the Orphan Well Association, and the AER.

The Court found in *Redwater* that receivers and trustees of AER licencees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the federal *Bankruptcy and Insolvency Act* (*BIA*). The Court found that the provincially mandated AER requirements were inoperative to the extent that they conflicted with the *BIA* under the doctrine known as paramountcy, which gives effect to federal law where provincial and federal laws conflict.

The AER noted that it, along with the Orphan Well Association, are appealing the Court's decision in *Redwater*.

Effective immediately however, the AER announced the following changes to minimize risk to Albertans:

- The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as nonroutine and may exercise its discretion to refuse and application or impose terms and conditions on an licence eligibility approval if appropriate in the circumstances.
- For holders of existing but previously unused licence eligibility approvals, prior to approval of any application, the AER may require evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when the licence eligibility was first granted.
- As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management ratio ("LMR") of 2.0 or higher immediately following the transfer.

The AER recognized that requiring an LMR of 2.0 or higher was a significant change. However, the AER noted that this change applies only to licensees that wish to acquire AER-licensed assets.

The AER noted that the reasoning behind the change was that some licensees that maintain the minimum LMR of 1.0 often find themselves in financial difficulty within weeks or months following an acquisition. The AER also stated that the measures were in furtherance of its mandate under section 2 of the *Responsible Energy Development Act* to provide for the efficient, safe, orderly and environmentally responsible development of energy resources in Alberta through the AER's regulatory activities.

The AER noted that an LMR of 2.0 can be achieved either through posting additional security with the AER, addressing existing abandonment obligations, or transferring additional assets. While the AER noted that the interim measures would inconvenience a number of stakeholders, it stated that the interim measures were necessary to ensure the protection of Albertans and their confidence in the regulatory system and AER licensees.

Bulletin 2016-18: Application Submission Requirements and Guidance for Reclamation Certificates for Well Sites and Associated Facilities
Bulletin – Facilities – Reclamation – Applications

The AER announced the release of *Specified Enactment Direction 002: Application Submission Requirements and Guidance for Reclamation Certificates for Well Sites and Associated Facilities* ("*SED 002*"), effective June 21, 2016.

SED 002 was issued pursuant to section 137 of the *Environmental Protection and Enhancement Act* ("*EPEA*") and section 12 of the *Conservation and Reclamation Regulation* ("*CRR*").

The new SED 002 sets out the information requirements for submitting a reclamation certificate application and replaces and supersedes the Government of Alberta *2010 Reclamation Criteria for Wellsites and Associates Facilities: Applications Guidelines*. SED 002 aligns the AER's requirements with the online submission process, and provides further guidance on how to prepare a complete application for a reclamation certificate.

The AER noted that it will continue to conduct environmental audits to ensure regulatory compliance for reclamation obligations.

The SED 002 can be viewed on the AER website here.

Bulletin 2016-19: Reducing Failures of High-Level Shutdown Systems
Bulletin – Facilities – Checklist

The AER announced, in an attempt to reduce the number of failures of high-level shutdown systems ("HLSS") at oil and gas production facilities, that it would introduce a checklist of best practices around types and frequencies of HLSSs.

The AER noted that it strongly recommends the use of the checklist as an effective tool for reducing failures. A copy of the checklist can be downloaded here.

The AER further noted that beginning in July 2016, field inspectors would assist in educating industry about the program during site visits.

In the event of a failure, the AER noted that it may request copies of completed checklists to assist in determining the adequacy and extent of the operator's efforts to prevent the incident.

AER Issues Environmental Protection Order to ConocoPhillips
Environmental Protection Order – Pipeline Failure

The AER announced that it had issued an environmental protection order ("EPO") under section 113 of the *Environmental Protection and Enhancement Act* and section 29 of the *Pipeline Act* to ConocoPhillips Canada Operations Ltd. ("Conoco"). The EPO was issued in response to a pipeline failure on one of Conoco's condensate pipelines, located between 01-36-060-03-W6M and 14-07-060-02-W6M. The AER noted that the pipeline failure resulted in the release of approximately 380 cubic meters of condensate approximately 65 kilometers northwest of Grande Cache, Alberta.

The EPO directed Conoco to:

- immediately contain the release and prevent it from spreading,
- identify anyone who may be affected by the release and make sure they are notified,
- control access to the site,
- collect water and soil samples from the site for analysis,
- develop a wildlife mitigation plan and detailed delineation and remediation plan,
- develop daily public reports and publish them to the Conoco website, and
- submit a final report to the AER.

The AER noted in its news release that much of the required work is already underway, and that it is currently conducting an investigation, the results of which will be published by the AER.

***Canadian Natural Resources Limited Regulatory Appeal of a Reclamation Certificate Refusal Boundary Lake South Field Proceeding No. 1837447*, 2016 ABAER 006**
Regulatory Appeal – Reclamation – Facilities

On May 2, 2014, Canadian Natural Resources Limited ("CNRL") applied for a reclamation certificate for a well site and access road in 11-9-083-13W6M (the "11-9 Site"). On October 20, 2014, the AER refused to issue the reclamation certificate. Consequently, on November 17, 2014, CNRL requested a regulatory appeal of the AER's decision to refuse the reclamation certificate.

CNRL had originally drilled a well at the 11-9 Site in 2001. The well was not productive, and was abandoned in October 2001. CNRL began conducting reclamation activities in 2002, seeding the 11-9 site with fescue, and spraying and mowing the 11-9 Site for noxious weeds.

The AER's reclamation programs group ("RPG") conducted an inspection of the 11-9 Site, and subsequently denied CNRL's application, providing the following reasons:

> Increased amount of incompatible vegetation (quackgrass patches) on portions of the well site and access road.
>
> The exemption justification form provided with the application is not acceptable as the quackgrass present on the site interferes with the landowner's use of the site for fescue production.

The AER set out the relevant legislation for land reclamations, noting that section 2 of the *Conservation and Reclamation Regulation* ("*CRR*"), specifies that the objective of conservation and reclamation is to ensure that specified land has an equivalent land capability. The *CRR* defines equivalent land capability to mean the ability of the land to support various land uses after conservation and reclamation similar to the ability that existed prior to an activity being conducted on the land, but that the individual land uses will not necessarily be identical.

Preliminary Matters

With respect to the appropriate point in time to consider when assessing whether the 11-9 Site meets the reclamation criteria, CNRL argued that the panel should not consider any information from before or after the site was assessed for compliance using the detailed site assessment ("DSA") in 2013, or the site inspection from RPG in 2014, as it submitted this was the only times there was a full evaluation of the site.

The landowner of the 11-9 Site submitted that the DSA did not accurately represent the state of the site, being only a snapshot in time, urging the AER to consider a broader time period.

The RPG presented argument that the appeal hearing was both a hearing on the record of the initial application, as well as a hearing *de novo*, where new evidence could be presented.

The AER determined that both the DSA and the inspection from RPG were relevant points in time to consider, but also held that site visits from AER filed staff and other photographs filed on the record would be considered, given that the new information is relevant to the underlying decision.

Issues

The AER defined the issues at stake in the regulatory appeal as:

- Whether the 11-9 Site met the reclamation criteria?
- Whether CNRL's application was complete and accurate?

Reclamation Criteria

The AER noted that section 137 of the *Environmental Protection and Enhancement Act* ("*EPEA*") provides that where specified lands (such as oil and gas well sites) must be conserved and reclaimed, the conservation and reclamation must be carried out in accordance with:

- Terms and conditions in the approval or other codes of practice;
- Terms and conditions of any environmental protection order;
- The directions of an inspector or Director appointed under *EPEA*; and
- The *EPEA* itself.

In looking at the applicable reclamation criteria, the AER considered the effects of quackgrass found at the 11-9 Site, including whether quackgrass was an undesirable plant, whether it interfered with the landowner's future use of the site, or ability to integrate the site.

The AER noted that the *2010 Reclamation Criteria for Wellsites and Associated Facilities for Cultivated Lands* (the "2010 Reclamation Criteria") describes weeds as undesirable or unwanted plants, and requires that such plants shall be controlled so that they do not impede land manager operability or management.

CNRL submitted that quack grass was not a prohibited weed under the *Weed Control Act* and submitted that it was not incompatible with the perennial pasture setting at the 11-9 Site.

The landowner submitted that he considered quack grass to be an undesirable plant and noted that it was difficult to eradicate its presence, and that it further reduced the value of certain seed crops on his land.

The RPG similarly submitted that quack grass can be an undesirable plant that can negatively affect cultivated crops, but could be used as pasture or hay and may be found on lists of preferred plants for rangelands.

The AER noted that Alberta Agriculture and Forestry categorized quack grass as a nuisance weed and that in this specific situation, Alberta's Institute of Agrologists considered it to be an undesirable but not a designate noxious weed. The AER therefore concluded that quack grass could be an undesirable plant if it interfered with the landowner's use of the site.

The landowner submitted that prior to the lease construction at the 11-9 Site, the 11-9 Site was planted to fescue from which the landowner harvested seed crops. The 11-9 Site had been maintained in fescue since 2201, while adjacent fields were rotated through different seed crops such as barley, wheat and canola since 2006.

The RPG submitted that the landowner's current use of adjacent lands for crops was a reasonable basis to determine that quack grass could be considered an undesirable plant since it competes with seeded crops, and could be costly to control.

CNRL submitted that the 11-9 Site was not currently being used for fescue or fescue seed production, and has been used as pasture for cattle grazing and equipment storage. CNRL submitted that quack grass did not interfere with these uses of the 11-9 Site.

The landowner replied that if he were to take control of the 11-9 Site at this time, it would need to be separated from the rest of his lands for several years and that herbicides would need to be applied for approximately three years.

The AER noted that the adjacent fields had not been used for pasture since 2006, and that reintegration of the site may include fescue seed production. The AER held that the landowner was therefore not using the site for pasture, and that the landowner's land management objective was to integrate the 11-9 Site into the landowner's existing crop rotation.

The AER therefore held that quack grass was an undesirable plant, holding that it would interfere with the landowner's use of the site.

The RPG provided evidence that the initial inspection was assessed against the 1995 reclamation criteria, instead of the *2010 Reclamation Criteria* and that the 11-9 Site would not have passed inspection otherwise.

The RPG submitted that the 11-9 Site should be reclaimed to a condition that would be manageable for the landowner, and would not be an obstacle to normal farming methods.

The AER determined that while the *2010 Reclamation Criteria* does not require the complete eradication of weed and noxious plants in order to issue a reclamation certificate, it does require that prohibited noxious weeds be destroyed and noxious plants be controlled. The AER held that CNRL had not sprayed the 11-9 Site for weeds since its inspection in 2013, and that CNRL therefore did not continue to control quack grass on the site.

Accordingly, based on the presence of quack grass on the 11-9 Site, the AER held that the 11-9 Site did not meet the reclamation criteria and had not been returned to an equivalent land capability.

<u>Completeness of CNRL Application</u>

CNRL stated that it sprayed the 11-9 Site for quack grass with Assure II in September 2012 and in June 2013, which it submitted killed or suppressed all above-ground growth of the grass, so it was not visible at the time of its inspection and application.

During the complaint inspection however, both the landowner and RPG identified patches of quack grass on the 11-9 Site. Further testing confirmed the presence of quack grass.

The RPG submitted that the application was therefore not complete or accurate, as the inspection and application failed to document the presence of quack grass at the 11-9 Site.

The AER held that the applications of Assure II to the 11-9 Site could reasonably have suppressed or controlled quack grass, and that it was therefore entirely reasonable that the inspection and application did not identify quack grass on-site. The AER therefore determined that the application was not incomplete or inaccurate, as the inspection and application were simply a "snapshot" in time, where there was no observable quack grass.

<u>Other Issues</u>

The RPG argued that the application was not complete since it did not include signed release letters setting out that the perimeter fence and culvert would remain in place. The RPG noted that the *2010 Reclamation Criteria* provides that facilities or features that are to remain in place must be approved by the landowner.

CNRL argued that these sorts of releases would normally be considered a "minor" deficiency that could be rectified within 30 days of the application, and that in any event, the culvert was the property of Alberta Transportation. CNRL also later provided a letter of release from Alberta Transportation during the hearing, allowing the culvert and other facilities to remain in place.

The AER held that the perimeter fence would need to be taken down before a reclamation certificate may be issued. However, as the landowner expressed a preference for the reclamation certificate to be issued prior to the removal of the fence, the AER did not find that the application was incomplete due to the absence of the fence release.

The AER also noted that communication between CNRL and the landowner, based on the record of the proceeding, was insufficient, and in its determination, not effective. The AER found that timely and effective communication would have likely addressed many of the difficulties and concerns raised during the course of the hearing.

The AER therefore reminded CNRL and the landowner that the AER's alternative dispute resolution was available for operational energy disputes of this nature.

The AER also noted that the passage of time, including significant delays in the inspection, application and complaint complicated the process greatly regarding the evidence in the proceeding. The AER held that a shorter timeframe would have reduced any potential for inaccuracies or discrepancies at the 11-9 Site between the application, inspection and subsequent visits.

<u>Order</u>

Based on the determinations above, the AER found that the 11-9 Site did not meet the *2010 Reclamation Criteria* and that CNRL's reclamation certificate application was accordingly incomplete. The AER therefore refused to issue a reclamation certificate for the 11-9 Site, but invited CNRL to apply for a reclamation certificate once the site met the *2010 Reclamation Criteria*.

Bearspaw Petroleum Ltd. – Proceeding 336 Application 1820596 – Pool Delineation, Crossfield Basal Quartz C & V Pools 2016 ABAER 007
Pool Delineation – Application

Bearspaw Petroleum Ltd. ("Bearspaw") applied to the AER pursuant to section 33(1)(d) of the *Oil and Gas Conservation Act* ("*OGCA*") requesting that the AER include Bearspaw's well located at 102/11-24-24-28W4M ("102/11-24") within the Crossfield Basal Quartz C pool. The 102/11-24 well is currently the only well in the Basal Quartz V pool.

Harvest Operations Corp., Nexen Crossfield Partnership, and ExxonMobil Canada Energy (the "Harvest Group") are the working interest owners in the Basal Quartz C pool, which has a gathering and processing system servicing the wells in the Basal Quartz C pool. The Harvest Group opposed Bearspaw's application.

Bearspaw submitted that its application was based largely on pressure data, showing that the Basal Quartz C and V pools were not separate. The Harvest Group submitted that the pressure data did not support the inclusion of the Basal Quartz V pool, arguing that the pools are actually separate, or that if there was communication between the pools, that the communication was not effective.

The AER framed the issue in dispute as whether the accumulation of gas in the Basal Quartz encountered by the 102/11-24 well is separate or appears to be separate from the accumulation of gas being produced by the C pool wells.

The AER noted that there are no prescribed factors that it must take into account when considering an application for a pool delineation under section 33(1) of the *OGCA*.

Geology

Bearspaw submitted that the Basal Quartz in the C and V pools was deposited into a braided fluvial system, whereas the Harvest Group submitted that the deposits occurred in a meandering system.

Bearspaw submitted that the Basal Quartz area was a large heterogeneous reservoir with highly variable porosity and permeability, which results in differences in the behaviour of the wells within the Basal Quartz.

Bearspaw also submitted that the well log data obtained showed that permeability and porosity within the C pool were within a reasonable range of values from those for the V pool.

The Harvest Group submitted that the Basal Quartz was comprised of up to four depositional cycles of deeply incised fluvial channel system sands, where several different mechanisms exist that could result in the separation of the pools. The Harvest Group also pointed to the presence of silica cement and clay in core samples taken from nearby wells as evidence of such separation within the reservoir.

The AER determined that the geology of the Basal Quartz was formed by a complex fluvial system, including both meandering and braided depositional facies, which could result in either the separation of reservoirs, or the establishment of larger heterogeneous pools.

Accordingly, the AER determined that the heterogeneity of the Basal Quartz did not establish on a balance of probabilities that the boundaries of the C pool should be redrawn to include the 102/11-24 well.

Gas Composition

Bearspaw submitted that the composition of the gas produced from two C pool wells and its own 102/11-24 well showed a marked similarity for nearly all components, except for iC5, nC5, C6 and C7, which yielded small but noticeable differences. Bearspaw explained that these differences arose largely from the sampling methods, with the C pool samples being taken at the separator, whereas the 102/11-24 sample was taken at the wellhead. Bearspaw submitted that the effect of these differences changed the values of the liquids components in the produced gas.

The Harvest Group provided no evidence with respect to gas composition.

The AER determined that while Bearspaw's explanation was reasonable, the gas composition evidence (taken either alone, or together with the geological evidence) was not sufficient to establish on a balance of probabilities that the gas accumulation in the V pool was separate or appeared to be separate from the C pool.

Pressures and Reservoir Characteristics

Bearspaw submitted that the static gradient pressure data for the 102/11-24 well set it apart from static gradient pressure readings for well in the C pool, noting that C pool wells had stabilized pressures from 3,300 kPa to 3,900 kPa (with one exception at 6,800 kPa), whereas the 102/11-24 well had an observed pressure of 12,296 kPa.

While the AER noted that expected pressures of wells in the same pool should be much closer, the AER noted that because the Basal Quartz reservoir was heterogeneous, the initial static gradient pressure readings did not provide conclusive evidence of the wells being in the same or separate pools.

The Harvest Group submitted that plotting pressure against time in a graph showed that the 102/11-24 well did not behave like the wells in the C pool. However, Bearspaw replied submitting that even among wells within the C pool, they did not behave the same way, providing evidence of higher pressures among wells within the C pool as demonstrative of the highly heterogeneous nature of the reservoir.

The AER panel therefore found that the well pressure data supported a finding of a highly heterogeneous pool with observable differences in depletion and pressure characteristics trending toward the south and south-southeast towards the 102/11-24 well, which is the least depleted area of the pool.

Harvest submitted that differences in initial pressures, and the lower apparent drainage at the 102/11-24 well was due primarily to:

- The heterogeneity of the C pool with highly variable porosity and permeability; and
- That the 102/11-24 well was in an as yet un-depleted portion of the C pool.

Bearspaw also cited pressure data from a static gradient test at a well located at 100/11-23-24-28W4M, which is not a producing well. Bearspaw submitted that the data from this well was 11,695 kPa, reflecting an approximate 32% decline from initial reservoir pressure as a result of depletion from nearby wells.

Bearspaw took the position that the only reasonable explanation for the falling pressures was that the Basal Quartz penetrated by the 102/11-24 well is being depleted by production from the C pool wells, and hence not separate from the C pool itself.

The Harvest Group replied, stating that the initial pressure of the 102/11-24 well was so different from the values for the other C pool wells, that it would not be reasonable to include it with the C pool.

The AER determined that the 100/11-23-24-28W4M well was likely depleted as a result of production of C pool wells, and that the bottomhole location of the well appears to have penetrated an area of the Basal Quartz reservoir that is more like the 102/11-24 well, than the C pool wells to the north.

However, in the course of providing its findings on whether the Basal Quartz pools were connected, the AER held that the monetary value of any reserves that may have been drained from around the 102/11-24 well was not relevant to the application. The AER reiterated that the test was whether the accumulation of gas in the Basal Quartz encountered by the 102/12-24 well was separate from the accumulation of gas in the Basal Quartz encountered by wells in the C pool. The AER held that the monetary value of any potential lost production was of no assistance in determining such a question.

The AER found that the 102/11-24 well had been experiencing drainage, noting that pressures over time reflected that the drainage was ongoing and sufficient to establish on a balance of probabilities that the accumulation of gas in the Basal Quartz encountered by the 102/12-24 well was not separate from that in the C pool.

Accordingly, the AER approved Bearspaw’s application, and re-designated the 102/11-24 well to the Basal Quartz C pool, and extending the C pool boundary to include the current Basal Quartz V pool.

ALBERTA UTILITIES COMMISSION

City of Lethbridge 2015-2017 Transmission Facility Owner General Tariff Application (Decision 21213-D01-2016)
Rates – Tariff

The City of Lethbridge ("Lethbridge") filed its general tariff application ("GTA") for approval with the AUC. Lethbridge requested approval of the following as part of its GTA:

- A revenue requirement of $6.3407 million in 2015, $6.3184 million in 2016 and $7.1156 million in 2017;
- Reconciliation and maintenance of Lethbridge's return on equity ("ROE") deferral account and direct assign deferral account;
- Reconciliation and maintenance of Lethbridge's hearing cost reserve account and self-insurance reserve account; and
- Acknowledgement of Lethbridge's compliance with outstanding directions from Decision 2013-364 and Decision 2013-417.

Lethbridge's requested revenue requirement for each of 2015, 2016 and 2017 were provided as follows:

Revenue Requirement ($000)	**2015**	**2016**	**2017**
Operating Costs	3,117.3	2,796.5	3,243.3
Depreciation	1,626.3	1,783.5	2,035.2
Cost of Capital	1,597.2	1,694.7	1,837.1
Sub-Total	6,340.7	6,274.7	7,115.6
Deferral and reserve accounts	-	43.5	-
Gross Revenue Requirement	**6,340.7**	**6,318.3**	**7,115.6**
Monthly Tariff ($)	**528,391**	**526,522**	**592,968**

Lethbridge submitted that the majority of the increases in its rate base and revenue requirement for 2016 and 2017 was attributable to the addition of the new Chinook 181S Substation and associated transmission line, which represents costs of $569,452 in 2016 and $755,131 in 2017.

<u>Operating Expenses</u>

Lethbridge submitted that it applied a six year historical average for overhead line expenses, given the cyclical nature of preventive maintenance work on overhead lines. Lethbridge also submitted that the purchase of a bucket truck in 2015 would serve to reduce external contractor costs, and allow Lethbridge to conduct more frequent inspections of overhead lines.

The Consumers' Coalition of Alberta ("CCA") submitted that the purchase of the new equipment served only to shift costs from contractors to internal labour, and did not significantly affect forecasts. Accordingly, the CCA submitted that the test year expenses be based on 2014 actual expenses with adjustments for inflation and growth.

The AUC agreed with Lethbridge that its overhead line expenses were cyclical in nature, and held that a six year average was reasonable, as it helped to smooth forecast costs. The AUC further held that the purchase of the bucket truck for the purposes of inspections was reasonable, despite the fact that Lethbridge did not provide a business case in support of the purchase. The cost of the truck itself was not significant in the AUC's determination.

With respect to overhead costs for administration, design, engineering and other services, Lethbridge forecasted overhead recoveries of approximately $0.103 million for 2015, $0.491 million for 2016, and $0.209 million for 2017.

The CCA submitted that the forecast costs represented a material variation from year to year. The CCA argued that earnings fluctuations ought to be minimized, and that the level of overhead capitalization should be based on sustainable levels of capital activity from year to year. Accordingly, the CCA recommended that Lethbridge be directed to review its overhead capitalization policy, based on sustainable capital activity levels.

Lethbridge replied that its current capitalization method was reasonable, in that the costs are explainable as well as the actual dollar amounts being reasonable.

The AUC held that Lethbridge was not bound by International Financial Reporting Standards (IFRS), but instead by the standards of the Public Sector Account Board. The AUC held that Lethbridge's capitalization method was reasonable and consistent with historical practice. Accordingly, the AUC approved the forecast overhead costs recoveries as filed.

Inflation

Lethbridge provided the following inflation figures in its application:

	2015	2016	2017
IBEW	3.5	3.5	3.5
CUPE	2.0	2.0	2.5
Administration	2.0	2.0	2.5
Contractor	2.5	2.5	2.5

Lethbridge noted that the forecast amounts for the International Brotherhood of Electrical Workers ("IBEW"), as well as the Canadian Union of Public Employees ("CUPE") were set by collective agreements already in place, which expire at the end of 2017. Lethbridge submitted that it has been its practice to match the inflation rate for management to the inflation rate for CUPE wages because that rate is the principal driver of management wage increases within the City of Lethbridge. Lethbridge submitted that any compaction between administration and CUPE rates would make it difficult to incent employees to take on increased responsibility in managerial roles.

The AUC noted that it was concerned about the yearly salary increases in all union and non-union areas for 2015, 2016 and 2017. However, noting that the economic conditions were different at the time Lethbridge entered into the contracts, the AUC noted that Lethbridge was bound by its agreements. The AUC held that although economic conditions do not warrant the application of escalators to administration and managerial salaries, it was prepared to accept the forecast based on the potential for compaction of employee and managerial wages.

The AUC however, noted that insufficient information was provided to support how Lethbridge adjusts for changes in market conditions in Alberta. Accordingly, the AUC directed Lethbridge in its next GTA, to:

- Explain the reasonableness of its forecast salaries and wages for all employees;
- Explain how its compensation adequately responds to economic downturns; and
- Provide the positioning of Lethbridge's total compensation relative to the Alberta marketplace and Lethbridge's justification for that positioning.

The AUC, for the same reasons outlined above, directed Lethbridge to apply for contractor rates at 0.0 percent escalation for the term of the GTA.

Depreciation

With respect to depreciation parameters, Lethbridge filed an updated depreciation study, which was not opposed by the CCA.

Changes to Lethbridge's proposed life curves for depreciation costs were approved as filed, with the exception of Supervisory Control and Data Acquisition ("SCADA") cost categories, net salvage amounts for transmission lines, and structures and improvements.

The AUC noted however, that Lethbridge filed a number of corrections to its depreciation expenses throughout the hearing. As a result, the AUC directed Lethbridge to update its schedules and revenue requirements in its compliance filing.

With respect to the accounting treatment of retired assets, gross salvage and removal, the CCA submitted that Lethbridge's depreciation practices had the potential to unduly increase the cost of new assets in service, and recommended that Lethbridge change its deprecation accounting to ensure that new asset costs are not burdened with the costs of assets retired and removed from service.

Lethbridge replied, stating that any such change to depreciation practices would not benefit ratepayers. Other departments within Lethbridge do not use such a depreciation system, and any potential cost savings would be offset by the administration costs of transitioning to a new system.

The AUC held that it shared the concerns raised by the CCA, holding that by capitalizing the cost of asset removals into the asset accounts, the balance of capital assets upon which the accumulated depreciation is determined is misrepresented by including removal costs that should be accounted for elsewhere. The AUC held that the effect of this calculation method would effectively overstate the annual amortization of reserve differences true-up calculation.

Accordingly the AUC determined that there was no rationale for Lethbridge to capitalize removal costs into its capital asset accounts, and accordingly directed Lethbridge to reflect all incurred removal costs in its accumulated depreciation accounts effective January 1,

2016. The AUC also noted that Lethbridge's depreciation study was often unclear, and at times conflicting with depreciation information filed in support of the application. As such, the AUC directed Lethbridge (in its next GTA) to adopt consistent account names and numbering conventions, identify any changes made to depreciation parameters, and to group its depreciation accounts into Transmission Plant and General Plant in both its depreciation study and its supporting materials.

Capital Structure

Lethbridge applied for a 2015 deemed capital structure of 36 percent equity and 64 percent debt, consistent with the AUC's findings in Decision 2191-D01-2015. Lethbridge applied for the same capital structure in 2016 and 2017 as a placeholder. Lethbridge forecasted a return on equity using the generic return on equity rate of 8.3 percent as approved in Decision 2191-D01-2015.

With respect to debt costs, Lethbridge submitted that it provides for capital plant investments through its Mill Rate Stabilization Reserve, which Lethbridge noted was analogous to injections of equity. Accordingly Lethbridge submitted that it did not directly incur debt, but included a proxy cost of debt as a 15-year rolling average lending rate of the Alberta Capital Finance Authority as of the mid-year date of July 2.

The AUC held that it was satisfied that the proposed capital structure and return on equity was in compliance with its prior findings in Decision 2191-D01-2015. Further the AUC held that maintaining such a capital structure as a placeholder for 2016-2017 until such time as a final determination could be approved was a reasonable approach.

Deferral Accounts

The AUC approved the continuation of Lethbridge's return on equity deferral account, direct assign deferral account, hearing cost reserve account and self-insurance reserve deferral accounts as filed, finding them to be reasonable.

Order

In light of the directions provided in this decision, the AUC directed Lethbridge to file a compliance filing no later than July 28, 2016.

ATCO Gas and Pipelines Ltd. (South) Pembina Expansion Project (Decision 21299-D01-2016)
Facilities – Pipeline

ATCO Gas and Pipelines Ltd. (South) ("ATCO") applied to the AUC to construct the Pembina Expansion Project, consisting of:

- the installation 10.8 kilometres of 610-millimetre outside diameter (OD) (the "Pembina Loop Pipeline"); and
- the installation of 9.4 kilometres of 610-millimetre OD pipe, in Brazeau County (the "Lodgepole Crossover Pipeline"),

(collectively, the "Project").

ATCO submitted that the Project would parallel existing linear disturbances for approximately 17.2 kilometres.

ATCO submitted that the Project would connect the existing Pembina Transmission Pipeline through new above-ground valve assemblies located at the Pembina Wye valve site and Pembina Lobstick Control Station, and would connect to NOVA Gas Transmission Ltd.'s Lodgepole Compressor Tie-In. ATCO submitted that the purpose of the Project is to increase the capacity of ATCO's existing Pembina Pipeline System, carrying sweet gas into the greater Edmonton area. ATCO estimated the total cost of the Project was $66.2 million, and would have a proposed in-service date of November 2016.

The AUC noted that the Project and related facilities would be located on private land within the "White Area" (the central southern, and Peace River areas generally suitable for agriculture) of Alberta, and would thus require a conservation and reclamation ("C&R") approval from the AER. ATCO submitted that it received its C&R approval from the AER on March 21, 2016, and would comply with the recommendations and mitigation measures set out in the C&R approval.

The AUC held that ATCO's evidence demonstrated a requirement to meet needed additional system capacity in its five-year supply/demand forecast in order to avoid a natural gas supply capacity shortfall in winter 2016-2017 in the greater Edmonton area. Accordingly, the AUC held that ATCO had demonstrated that there was a need for the Project.

The AUC, in noting that there were no outstanding public or industry objections or concerns, and noting that ATCO committed to comply with the terms and conditions of its C&R approval, held that the Project was in the public interest in accordance with section 17 of the *Alberta Utilities Commission Act*. The AUC therefore granted approvals to ATCO to construct the Project.

Oldman 2 Wind Farm Limited – Review of Decision 3521-D01-2015: Mr. Yanke and Mr. Huebner Noise Complaints, July 20, 2015 (Decision 20843-D01-2015)
Review and Variance – Noise Complaint

Oldman 2 Wind Farm Limited ("Oldman 2") filed an application for a review of Decision 3521-D01-2015, which dealt with noise complaints from Mr. Yanke and Mr. Huebner in respect of the Oldman 2 wind farm's compliance with AUC Rule 012: *Noise Control* ("Rule 12"). In that decision, the AUC held that Oldman 2 was not in compliance with Rule 12, as it did not meet the permissible sound level of 40 dBA L_{eq} nighttime at the Yanke and Huebner residences. The AUC had ordered Oldman 2 to restrict operations of wind turbines at the Oldman 2 wind farm contributing to the non-compliance.

Oldman 2 submitted that the AUC made errors of law or jurisdiction in directing the restricted operation of the Oldman 2 wind farm. Oldman 2 alleged that the AUC:

- failed to consider, or misconstrued the permissible sound level applicable at the Yanke and Huebner residences (located 315 and 475 from turbines on the Oldman 2 wind farm), arguing that the AUC had to determine the cumulative sound level existing at the time of the construction of the residences in question;
- erred in rejecting Oldman 2's approach to determining the cumulative sound levels that existed at the time the residences were constructed; and
- was required to go through the exercise of determining a "correct" cumulative sound level in order to compare that figure to the permissible sound level set out in Rule 12.

Oldman 2 submitted that Decision 3521-D01-2015 has forced the restriction of operations of the wind farm at nighttime, reducing the revenue generated by the wind farm. Oldman 2 estimated the lifetime loss of production totalled approximately 9,500 MWh.

Mr. Huebner submitted a letter of comment to the AUC, stating that little has changed in respect of the noise levels on his residence, and submitted that nothing short of removing the offending turbine would remedy his concerns.

Mr. Yanke also submitted a letter of comment stating that the noise levels at his residence had not changed, leading him to question whether Oldman 2 was complying with Rule 12. Mr. Yanke also posed questions in respect of how the AUC planned to enforce Decision 3521-D01-2015, and requested that an ongoing data log be provided to ensure that permissible nighttime sound levels are being observed.

The AUC held that the purpose of Rule 12 is to protect persons living near a facility from noise emanating from the facility. Rule 12 does not govern the conduct of a resident living near such facilities. Accordingly, the AUC held that the determination of the permissible sounds levels uses a cumulative sound level, which includes the assumed or measured ambient sound level, and any existing or approved (but not yet constructed) energy related facilities. In this light, the AUC held that Rule 12 must be given a broad and liberal construction in a manner which meets the purpose of the case at hand.

The AUC found that the original hearing panel correctly took into account the fact that Mr. Yanke and Huebner's houses were purchased two years after Oldman 2 had obtained approval.

The AUC held that Oldman 2 failed to demonstrate that the hearing panel committed any error of law or jurisdiction in Decision 3521-D01-2015 that could lead the AUC to materially vary or rescind its decision. Accordingly, the AUC dismissed Oldman 2's review application.

ATCO Gas and Pipelines Ltd. 2016 Weather Deferral Account (Rider W) Application (Decision 21584-D01-2016)
Rates – Deferral Account

ATCO Gas and Pipelines Ltd. ("ATCO") applied for approval of the collection of ATCO Gas North and ATCO Gas South's weather deferral account ("WDA"), also known as Rider W, balances as of April 30, 2016. ATCO submitted that the balance of the WDA would result in a collection of approximately $28.548 million for ATCO Gas North and $23.394 million for ATCO Gas South.

ATCO further requested that future WDA applications have rider periods ending on April 30 of each year.

The AUC explained that the purpose of the WDA was originally to allow ATCO to manage the revenue risk to the utility resulting from differences in actual temperatures compared to weather forecasts, and the impacts that would have on delivery revenues.

ATCO proposed to collect the WDA through Rider W for 10 months, effective July 1, 2016 to April 30, 2017. Given the magnitude of the collections, ATCO stressed that a collection date effective as soon as possible was required to allow collection on a timely basis, while the 10 month collection period was requested in order to avert any possible rate shock from the implementation of Rider W.

ATCO submitted that the Rider W amounts for South low-use customers was $0.269 per gigajoule (GJ), while it amounted to $0.252 per GJ for South medium-use customers. ATCO noted that on an annualized basis, the

Rider W would amount to approximately $30 for an average low-use residential customer, and $693 for a medium-use customer. For North customers, ATCO submitted that the Rider W amounts for North low-use customers was $0.294 per GJ while it amounted to $0.280 per GJ for North medium-use customers. ATCO noted that on an annualized basis, the Rider W would amount to approximately $32 for an average low-use residential customer, and $770 for a medium-use customer.

In response to an AUC information request, ATCO submitted that the percentage impact on a typical customer bill would be at most 6.08 percent (for medium-use customers in the North). As a result, ATCO argued that the difference between a 12-month collection period and a 10-month collection period would be minimal. ATCO submitted that it preferred a 10-month collection period to ensure that there was no confusion over any potential overlap between annual Rider W amounts, and to avoid intergenerational equity concerns.

The AUC held that the methodology used by ATCO to calculate the WDA and Rider W were consistent with its previous approvals for past WDA and Rider W applications. The AUC also found that there would be minimal customer confusion, and that the 10-month collection period ending April 30, 2017 was reasonable. Accordingly, the AUC approved the WDA collection balances of $28.548 million for North customers, and $23.394 million for South customers by way of its Rider W, effective July 1, 2016 to April 30, 2017.

AltaGas Utilities Inc. and AltaGas Utility Holdings Inc. 2016 Debenture and Common Shares Issue Application (Decision 21578-D01-2016)
Debenture – Common Shares

AltaGas Utilities Inc. ("AUI") and AltaGas Utility Holdings Inc. ("AUHI") applied for approval for the issuance of debentures and common shares pursuant to section 26(2)(a) of the *Gas Utilities Act*. AUI and AUHI requested approvals no later than June 28, 2016 so that interest payments on its applied-for debentures would mirror the interest payment dates of the most immediately preceding 10-year term debt from AltaGas Ltd., their parent company.

Debentures

AUI and AUHI requested the following as part of their debenture application:

- Approval for AUI to issue an inter-company debenture of $45 million to AUHI maturing on April 7, 2026 (the "AUI 2016 Debenture");
- Approval for AUHI to issue to AltaGas Utility Group Inc. an inter-company debenture of $45 million maturing on April 7, 2026 (the "AUHI 2016 Debenture");
- Approval for the issue date of the AUI 2016 Debenture and AUHI 2016 Debenture of June 29, 2016;
- Approval of the annual coupon rate of 4.12 percent per annum, and issue costs of 0.08 percent per annum; and
- Approval of the purposes of the issues.

AUI and AUHI submitted that the proceeds from the AUHI 2016 Debenture would be used by AUHI to subscribe for the AUI 2016 Debenture. The proceeds from the AUI 2016 Debenture would then repay a previous $20 million AUI debenture to AUHI, which expires on June 29, 2016, with the remainder being used to finance AUI's 2016 capital expenditures, working capital requirements, and maintenance of an appropriate capital structure.

AUI submitted that it has been its practice to obtain debt financing through its parent company through a series of inter-company transactions.

The AUC explained its prior findings in Decision 2009-176, where it held that debt rates (or coupon rates) incurred by the parent company should be applied to the debt of AUI.

On April 7, 2016, AltaGas Ltd. issued $350 million of 10-year medium term notes with a coupon rate of 4.12 percent, maturing on April 27, 2026. Accordingly, the AUC held that the coupon rates requested by AUI and AUHI were consistent with prior decisions.

The AUC found that, based on the opinion provided by counsel for AUI and AUHI, that the issuance of debentures was made in accordance with applicable law. The AUC also determined that the purposes of the debentures as set out by AUI and AUHI were reasonable, and met the requirements of Section 26(2)(a) of the *Gas Utilities Act*.

The AUC noted that, although the debentures were approved, the AUC's approval did not remove the duty from AUI and AUHI to demonstrate that the debentures ultimately acquired must have been obtained and used prudently, which the AUC noted would be examined in AUI and AUHI's next cost-of-service application.

Common Shares

AUI and AUHI requested the following as part of their common shares issuance application:

- Approval of AUI's issuance of up to 269,795 Class A common shares of AUI to its direct parent, AUHI, for a maximum amount not to exceed $12 million;
- Approval for AUHI to issue up to 3,279,902 common shares of AUHI to its direct parent, AltaGas Utility Group Inc., for a maximum amount not to exceed $12 million; and
- Approval of the purposes of the issues.

AUI and AUHI estimated the maximum net proceeds from the issuance of AUHI share would amount to $12 million. As noted in the debenture applications, these funds would be used by AUHI to subscribe for the AUI shares.

AUI and AUHI submitted that the proposed issuance of shares would have no effect on the control of the corporations. AUI submitted that the proposed share issuance would result in a 42 percent common equity ratio, which would approximately reflect its approved ratio in Decision 2191-D01-2015, while taking into consideration its own 2016 capital requirements.

The AUC found that, based on the opinion provided by counsel for AUI and AUHI, that the issuance of common shares was made in accordance with applicable law. The AUC also determined that the purposes of the issuance of common shares as set out by AUI and AUHI were reasonable, and met the requirements of Section 26(2)(a) of the *Gas Utilities Act*.

Accordingly, the AUC approved the application as filed.

The AUC noted however that AUI and AUHI were still required to demonstrate in their respective next cost-of-service application, that the debentures acquired had been obtained and used prudently.

ATCO Gas and Pipelines Ltd., CU Inc. and Canadian Utilities Limited Disposition of the Calgary Service Centre (Decision 21321-D01-2016)
Disposition – Rates

ATCO Gas and Pipelines Ltd., CU Inc. and Canadian Utilities Limited (collectively, "ATCO") applied for approval to sell their Calgary Service Centre ("CSC") located at 1040 – 11 Avenue S.W. in Calgary, Alberta.

ATCO had previously applied for approval to dispose of the CSC in Decision 20528-D01-2015, where the AUC denied the disposition on the basis that ATCO had failed to provide sufficient evidence to satisfy the AUC's "no-harm" test to ratepayers. The AUC had previously found that the proposed disposition was outside the ordinary course of business.

ATCO proposed to structure its disposition of the CSC as follows:

- ATCO Gas and Pipelines Ltd. transfers the non-utility assets to ATCO Real Estate Holdings Ltd. ("Real Estate") in exchange for cash and preferred shares of Real Estate.
- Real Estate redeems the preferred shares for a promissory note.
- ATCO Gas and Pipelines Ltd. distributes the Real Estate promissory note to CU Inc. as a dividend. CU Inc. distributes the promissory note to Canadian Utilities Limited ("Canadian Utilities"), as a dividend.
- Canadian Utilities contributes the promissory note to Real Estate as a subscription for additional common shares of Real Estate. The promissory note is cancelled.

The AUC assessed the application to determine whether the transaction had any adverse financial or service level impacts to customers.

<u>Service Quality</u>

ATCO submitted that it has since received positive feedback from customers, especially in respect of in-person service applications.

None of the interveners in the application raised any concerns regarding service applications.

The City of Calgary ("Calgary") however, raised concerns regarding ATCO's emergency response time metrics for events such as fires, explosions, blowing gas, gas leaks, odours or carbon monoxide.

ATCO submitted that its service standard is to respond to 87 percent of emergencies within 60 minutes. ATCO further noted that its recent emergency response performance in the Calgary region was consistent with historical levels, averaging 95.3 percent year-to-date for 2016.

Calgary however, submitted that ATCO presented those results on an aggregate basis for ATCO's North and South service areas, and further opposed ATCO's submission on the basis that two months of year-to-date data was not evidence of a trend.

The AUC determined that customers were no worse off due to the relocation of staff from the CSC. The AUC also determined that ATCO's evidence regarding quality of service impacts was persuasive, noting that actual emergency response times compared to estimated response times were well within the parameters set by

AUC Rule 002: *Service Quality and Reliability Performance Monitoring and Reporting for Owners of Electric Distribution Systems and for Gas Distributors*. The AUC also noted that the staff who typically respond to emergencies were unaffected by the closure of the CSC, and therefore such response times would likely be unaffected.

Accordingly, the AUC held that ATCO's proposed disposition would not adversely affect the quality of service for customers.

Impact to Rates

ATCO submitted that the net book value of the CSC assets were approximately $2,392,000, with annual operating costs of approximately $506,000.

ATCO submitted that it had retained an architecture and design firm to provide estimates for potential improvements required to make the CSC suitable for long-term use. ATCO estimated that the cost of improvements, over an 18 month period, would total $7.21 million, including:

- $2.8 million to address functional deficiencies in the heating, ventilation and air conditioning;
- $1.0 million to address building code deficiencies;
- $1.7 million to address cosmetic deficiencies, including flooring, ceilings, doors and exterior finishes.

ATCO confirmed that it had previously withdrawn the CSC assets from service effective November 1, 2015 and had relocated its employees from the CSC elsewhere. ATCO submitted that the required renovations needed to relocate the employees came to $1.47 million, $0.03 million lower than estimated. ATCO argued that although its rate base increased by $1.47 million to renovate other facilities, the cost of keeping the CSC in operation would have retained $2.4 million in rate base, plus $7.2 million over the next 18 months for improvements needed to the CSC.

ATCO submitted that it did not expect any material increase in operating costs at its remaining service centres as a result of absorbing employees from the CSC, as ATCO noted that most operating costs would be incurred independent of occupancy.

The AUC accepted ATCO's evidence that the $506,000 estimate of 2014 operating costs was a reasonable representation of the annual operational costs of the CSC would be. The AUC also held that the quantification of actual renovation costs for existing service centres was persuasive in demonstrating that the risk of unknown costs to ratepayers arising from the transaction was significantly reduced.

The AUC held therefore that the closure of the CSC would not adversely affect the rates paid by ratepayers.

Order

The AUC, having found that customers would not suffer any adverse financial or service level impacts, held that ATCO had satisfied the "no-harm" test. Accordingly the AUC approved the disposition as filed, and directed that ATCO's rate base be adjusted to reflect the removal of the CSC from service at the end of its current performance based regulation term.

ATCO Electric Transmission and ATCO Pipelines Application for ATCO Electric Transmission 2015-2017 and ATCO Pipelines 2015-2016 Licence Fees (Decision 21029-D01-2016)
Rates – Licence Fees – Tax

ATCO Electric Transmission, ATCO Electric Ltd, and ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. (collectively, "ATCO"), pursuant to a direction from the AUC, applied for a joint licence fee application to include in ATCO's respective revenue requirements, amounts corresponding to licence fees they are required to pay to ATCO Ltd. for the use of intangibles and associated benefits that ATCO receives from ATCO Ltd. Each of the ATCO companies forecast the following licence fees, respectively:

- ATCO Electric Transmission - $2.7 million in 2015, $3.1 million in 2016 and $4.7 million in 2017; and
- ATCO Pipelines - $0.6 million in 2015, $0.7 million in 2016.

These amounts had previously been made subject to placeholder treatment by the AUC.

Originally, in Proceeding 3577, ATCO Pipelines, on behalf of itself and Gowling Lafleur Henderson LLP asserted that there was a domestic *Income Tax Act* obligation requiring ATCO Ltd. to charge licence fees to ATCO Pipelines under section n247 of that enactment.

As a result of objections filed by the Utilities Consumer Advocate ("UCA") the AUC initiated a separate process to consider the income tax obligations of ATCO with respect to licence fees.

ATCO submitted that the licence fees are intended to compensate ATCO Ltd. for its subsidiaries' use of intangibles and benefits that they receive as a result of their relationship to the parent corporation. ATCO submitted that the intangibles included purchasing power benefits, economies of scale, as well as use of the ATCO name, trademarks, intellectual property, and know-how.

ATCO Ltd. imposed licence fees on all of its subsidiaries on January 1, 2015 commensurate with the fair market value of benefits received, which ATCO Ltd. set at one percent of operating profit of the applicable subsidiary. ATCO submitted that these fees were established to comply with Canadian tax law requirements to ensure that it realizes fair market value for benefits it provides to subsidiaries, using transfer pricing concepts.

ATCO submitted that their request to include licence fee amounts in revenue requirements was justified, as the net benefits customers derived far outweighed the licence fee amounts. ATCO noted that analyses performed by Ernst & Young as well as Aon Canada estimated the financing and insurance cost savings between $4.4 and $10.5 million annually for each subsidiary for financing costs, and between $1.1 and $1.6 million for leveraging purchasing power.

ATCO argued that the payment of licence fees was consistent with the expectation that utilities seek cost efficiencies that result in net benefits to customers in providing utility services. In accordance with the stand-alone principle, ATCO submitted that the licence fees guarded against cross-subsidization between ATCO's various affiliates.

The Consumers' Coalition of Alberta ("CCA") stated the issue before the AUC as being whether amounts paid by ATCO to ATCO Ltd. should be included in the companies' respective revenue requirements. The CCA argued that the proposed licence fee is not supported by any costs, nor was it required for utility service, and that no risk of tax liability arises if customers do not pay the licence fee. The CCA submitted that ATCO was already paying their share of costs through corporate allocations which are included in the revenue requirement. The CCA further argued that the tax obligations cited by ATCO apply to transfer pricing on intangible property for cross-border transaction, not domestic inter-affiliate transactions. Accordingly, the CCA requested that the application be dismissed, and the amounts excluded from the companies' respective revenue requirements.

The City of Calgary similarly opposed the application, arguing that ATCO failed to demonstrate that the requested costs were just and reasonable, or required for the provision of utility service. Both Calgary and the CCA expressed concern that ATCO simply accepted the licence fees being imposed upon it by ATCO Ltd., and did not seek independent legal advice on the imposition.

The UCA submitted that the licence fee was not a true cost and was not prudently incurred by ATCO. The UCA submitted that ATCO did not demonstrate that the value to ratepayers from the use of the ATCO name, trademarks, intellectual property, and know-how. The UCA argued that once the double counting of management expertise was accounted for, the only remaining value would be for trademarks and advertising benefits. However, the UCA argued that such benefits were in fact unnecessary in a monopoly service with a captive customer base, and therefore questioned the legitimacy of the expenses.

The UCA also argued that, even if the *Income Tax Act* did require the payment of licence fees, the UCA argued that any obligation to do so would arise from ATCO's own choice of corporate structure. Accordingly, if ATCO had structured under a single corporation, the costs of licence fees would be zero. Therefore the UCA argued that such costs should be denied, as they are voluntary on ATCO's part.

The AUC held that customers should pay no more than what is necessary to receive service, citing the Supreme Court of Canada in *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission)*.

Based on the evidence provided, the AUC determined that section 247 of the *Income Tax Act* did not impose a requirement on ATCO Ltd. to charge its domestic subsidiaries a licence fee. The AUC accordingly rejected that ATCO would be exposed to tax liability as a result of any failure to impose such a licence fee.

The AUC held that ATCO's valuation methodology for patents, goodwill and advertising trademarks were problematic, as it failed to explain how such benefits are necessary for and valuable to a monopoly service such as ATCO's. Accordingly, the AUC assigned ATCO's evidence in this regard only minimal weighting. As a result, the AUC was not persuaded that licence fees were any different from corporate signature rights, which it noted had previously been denied inclusion into revenue requirement.

With respect to ATCO's submissions on group economy benefits, the AUC held that it was incumbent on ATCO to provide a consideration of all of the costs and benefits of the relationship between ATCO and ATCO Ltd., holding that absent a complete picture of such costs and benefits, there is a strong likelihood that the inclusion of such licence fees in revenue requirement would not constitute just and reasonable rates.

The AUC held that the licence fees payable by ATCO did not constitute costs reasonable incurred for the provision of utility services. Additionally, any question of whether or not ATCO Ltd. was obligated to charge the licence fee was, in the AUC's determination, not dispositive of whether the amounts paid by ATCO should be included in revenue requirements. The AUC determined that ATCO had given no effort to critically assess or otherwise understand or obtain independent legal advice on ATCO Ltd.'s valuation of the licence fee with a view to obtaining fair market value for their own customers. The AUC held that such behaviour was inconsistent with what might be reasonably expected of a standalone entity. Accordingly the AUC denied ATCO's application in its entirety.

The AUC directed ATCO to remove the licence fees costs/placeholders from their respective revenue requirements.

NATIONAL ENERGY BOARD

Imperial Oil Resources Ventures Limited Mackenzie Gas Project – Request for an Extension of the Sunset Clauses
Time Extension – Pipeline – Facilities

Imperial Oil Resources Ventures Limited ("IORVL") requested an extension to condition 74, being the sunset clause, in the approvals for the Mackenzie Valle Pipeline ("MVP") and the Mackenzie Gathering System ("MGS") from December 31, 2015 to December 31, 2022.

Both projects form part of the Mackenzie Gas Project ("MGP") which consists of 1,842 kilometers of pipelines, a processing plant, and the development of three natural gas fields in the Mackenzie Delta area of the Northwest Territories ("NWT") for transportation to Alberta for southern markets. The original sunset clause for the MGP provided as follows:

- Unless the NEB otherwise directs, this Certificate shall expire on 31 December 2015 unless construction in respect of the Mackenzie Gas Project has commenced by that date.

IORVL submitted that construction would not begin before the December 31, 2015 sunset date, given the current state of natural gas market conditions, which rendered the project uneconomic at the time. IORVL submitted that the extension would provide time to see if market prices would sufficiently recover. IORVL submitted that it did not see any material changes to the MGP, and that anticipated impacts from the MGP would be consistent with the original application and approvals.

Fourteen parties submitted letters of comment regarding the extension application, eight of which were in support of the extension. Of the six letters opposing the extension, some of the commenters submitted that the extension of the sunset clauses would effectively allow the proponent to tie up resources, which should be opened up to other investors, noting that IORVL has had ample time to commence the MGP, but has made little or no progress to date. Others opposed the extension due to changes in circumstances, including climate change, water issues in the Mackenzie River, Caribou population declines since the issuance of the decision, and devolution of authorities to NWT.

IORVL replied, submitting that the approvals were permissive, not exclusive, and as such, IORVL was not required to construct any facilities, nor did the approvals preclude other proponents from applying for other facilities.

The NEB recognized that the MGP is not economically feasible under current market conditions, which may take many years to recover. The NEB also determined that changed circumstances relating to climate change and environmental impacts were adequately addressed in the original 115 conditions imposed by the NEB on the MGP, including submission of a report on the effects of climate change following consultation with stakeholders.

The NEB determined that devolution of powers to NWT for regulating certain oil and gas activities did not impact its consideration to extend the approvals, given that the regulatory authorities for NWT and the NEB have since entered into a memorandum of understanding and service agreement, allowing each to coordinate on regulatory projects that overlap in jurisdiction.

The NEB noted that, in providing its original decision on the MGP, gas market conditions were low, and further noted that the five year sunset clause as originally worded was meant to give an opportunity for natural gas from the Mackenzie Delta to compete with other gas supply sources, such as shale gas and tight gas.

Accordingly, the NEB held that the MGP was still in the public interest, and that the original 115 conditions imposed on the MGP continue to apply, which would require the MGP to be designed, constructed and operated in a safe manner to protect both people and the environment.

The NEB therefore approved IORVL's request to extend the sunset clause to December 31, 2022, and will seek approval from the Governor in Council for the variance of the condition.