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DECISIONS

REGULATORY
LAW CHAMBERS

Regulatory Law Chambers *is a Calgary-based boutique law firm dedicated to excellence in energy regulated matters. We have expertise in oil and gas, electricity, renewable energies, climate change, tolls and tariff, regulated commercial, compliance and environmental legal matters. We frequently represent clients in proceedings before the Alberta Energy Regulator, the Alberta Utilities Commission, the National Energy Board, the Courts, and in arbitrations and mediations.* ***Our advice is practical and strategic. Our advocacy is effective.***

*This monthly report summarizes energy decisions or resulting proceedings from applications before the Alberta Energy Regulator ("**AER**"), the Alberta Utilities Commission ("**AUC**") and the National Energy Board ("**NEB**"). For further information, please contact Rosa Twyman at Rosa.Twyman@RLChambers.ca or 403-930-7991 or Lynn McRae at Lynn.McRae@RLChambers.ca or 403-930-7995.*

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ALBERTA ENERGY REGULATOR

Canadian Natural Resources Limited – Application for the Kirby Expansion Project (Decision 2014 ABAER 006)
Expansion Project

Canadian Natural Resources Limited ("CNRL") applied for approval to develop 72 new surface well pads and expand previously approved central processing facilities and associated infrastructure. The proposed expansion would use Steam Assisted Gravity Drainage ("SAGD") to produce approximately 13,515 cubic metres per day of bitumen, bringing the project to a total production and processing capacity of 22,260 cubic metres per day of bitumen (the "Kirby Expansion Project").

Nine interested parties requested a hearing into the Kirby Expansion Project. Three of the parties withdrew their requests after resolving their concerns with CNRL. The Panel found that none of the remaining parties requesting a hearing had demonstrated that they may be directly and adversely affected by the AER's decision. Accordingly, the AER issued the decision as a notice of cancellation of the hearing, and that the Kirby Expansion Project application would be referred to AER staff for processing and disposition.

Licensee Liability Rating Program Changes (AER Bulletin 2014-11)
Licensee Liability Rating Program

On May 1, 2014, phase two of three phases in the Implementation Plan of the Licensee Liability Rating ("LLR") Program took effect. The objective of the Implementation Plan is to better align the LLR Program with actual abandonment and reclamation costs. As a result, the following values changed in the LLR Program:

(a) Increased deemed well abandonment liabilities by an additional one-third towards 2012 values;

(b) Increased deemed assets by an additional one-third towards the 2012 average industry netback;

(c) Increased facility abandonment costs for each well equivalent from $10,000 to $17,000; and

(d) Increased all existing regional reclamation liability costs by 25 per cent.

Canadian Natural Resources Limited – Modified Steaming Application (AER News Release 2014-04-17)
Steaming Operation – Conditions

The AER approved Canadian Natural Resource Limited's ("CNRL") application to modify steaming at phases 23 and 24 of CNRL's Primrose and Wolf Lake operations.

The AER issued the approval outside of the hearing process, as the AER had previously restricted steaming operations due to a flow-to-surface incident of bitumen emulsion in July of 2013. The AER approved the application to modify the steaming practices, provided that CNRL conduct no steaming within 1 kilometer of the well flow-to-surface release point.

Revisions to Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting Requirements (AER Bulletin 2014-13)
Flaring – Venting

Directive 060 was revised following feedback from the public industry and AER staff, as well as from the Canadian Association of Petroleum Producers ("CAPP"). The changes to *Directive 060* align with changes proposed by Alberta Environment and Sustainable Resource Development ("ESRD") to the Government of Alberta's *Air Quality Model Guideline* and *Non-Routine Flaring Management: Modelling Guidance.* The changes regarding non-routine dispersion modelling revisions are based on recommendations from CAPP's Non-Routine Flaring Task Team. The proposed revisions are intended to bring hydrocarbon odour requirements in alignment with the *Environmental Protection and Enhancement Act* and existing odour requirements for processing plants in the *Oil and Gas Conservation Rules.*

ALBERTA UTILITIES COMMISSION

East Airdrie Water System – Order For Amendment to Decision 2014-017: Enforcement Order for Failure to Furnish Safe, Adequate and Proper Water Service (Decision 2014-079)
Water Service – Seized Facilities

The AUC's Retail Energy and Water Division requested a revision to the expiry date in Decision 2014-017 from April 30, 2014 to April 1, 2014. The North East Water System Ltd. ("NEWS") facilities had previously been seized by the AUC for failure to furnish safe, adequate and proper service to customers of the East Airdrie water service area. The Sharp Hills Residents' Association, supplied by the NEWS facilities, had advised the AUC Retail Energy and Water Division that arrangements had been made for an alternative supply of water, and further advised that it no longer required service from the NEWS facilities after March 31, 2014.

As the AUC's possession and operation of the NEWS facilities was no longer required to give effect to Decision 2014-017 after March 31, 2014, the AUC amended the order contained in Decision 2014-017 to expire on April 1, 2014 at 12:00 pm (noon) local time.

AltaLink Management Ltd. – Temporary Switching Station and Transmission Line in the Southeast Calgary Area (Decision 2014-080)
Temporary Facilities

AltaLink Management Ltd. ("AltaLink") applied to alter the 139-kilovolt (kV) 850L and 727L transmission lines by connecting them through the 850L Temporary Switching Station during the construction of the 1109L, 1064L and 1065L transmission lines for the Foothills Area Transmission Development. The 850L Temporary Switching Station would occupy an area of 55 metres by 45 metres for three 138-kV breakers and other controls; as well as approximately 820 metres of temporary 138-kV transmission line to connect the 850L and 727L transmission lines to the 850L Temporary Switching Station. AltaLink also applied for a minor change to the deflection points for the 850L transmission line.

The AUC found that there were no outstanding technical, routing, environmental or noise concerns associated with the applications, as no submissions were received objecting to the application.

As the applications were only of a temporary nature, and would not affect the final routing and operation of final approvals held by AltaLink, the AUC declined to alter the final approvals and issued temporary approvals instead.

ATCO Gas – Application for Administration of a Province-wide Load Balancing Deferral Account (Decision 2014-078)
Load Balancing

ATCO Gas, a division of ATCO Gas Pipelines Ltd., ("ATCO Gas") requested approval to administer its north and south load balancing deferral accounts ("LBDA") as a single province-wide LBDA and to close the north and south LBDA's, as a result of the commercial integration of ATCO Pipelines and NOVA Gas Transmission Ltd.

In response to the Office of the Utilities Consumer Advocate and the Consumers' Coalition of Alberta requests for review of imbalance tolerance limits, the AUC directed ATCO Gas to continue to monitor its existing imbalance window parameters and make the data available at future industry committee meetings regarding load balancing.

The AUC approved the proposed province-wide LBDA based upon the following cost benefit analysis:

- Reduced administrative costs for both ATCO Gas and retailers;
- Reduced carrying charges for a province-wide LBDA; and
- Resulting cost savings are expected to exceed the cost of the imbalance reporting information system modifications associated with the change.

ATCO Gas will continue to use the same methodology and rate design in the province-wide LBDA pending review in the final north and south Rider L proceeding.

AltaLink Management Ltd. – North Central Alberta Telecommunications Tower Salvage Project (Decision 2014-081)
Salvage

AltaLink Management Ltd. ("AltaLink") applied to salvage telecommunications towers.

As no new construction was included in this application, notice of application was not required, and no hearing was held as the salvage would not directly and adversely affect the rights of a person. Replacement towers at all four locations had been previously approved and completed.

The application included an avian protection plan to mitigate adverse interactions with birds and inspect for evidence of nests or nesting activities prior to commencement of salvage.

The AUC approved the decommissioning and salvage of the telecommunications towers.

Enel Alberta Wind Inc. – Time Extension to Complete Castle Rock Ridge Wind Power Plant (Decision 2014-082)

Enel Alberta Wind Inc. ("Enel"), applied for a time extension from March 31, 2014 to March 31, 2017 to complete the construction of wind turbine generators at the Castle Rock Ridge power plant.

Enel submitted that it required the time extension due to delays from associated projects, such as the Southern Alberta Transmission Reinforcement, and submitted that routing details for a transmission line running from Goose Lake 103S substation to Chapel Rock 491S substation may require Enel to eliminate some wind turbine generators to accommodate the right-of-way and routing of the transmission line.

The AUC found that the requested time extension was minor in nature, but necessary to facilitate the completion of the Castle Rock Ridge power plant. Accordingly, as the application itself was held to be minor in nature, no hearing was held. The AUC granted the time extension to Enel.

Horizon North Logistics Inc. – Temporary Power Plant at MacKay River Commercial Project Worker Campsite (Decision 2014-083)

Horizon North Logistics Inc. ("Horizon North") applied for an exemption from section 11 of the *Hydro and Electric Energy Act* to operate a temporary isolated power plant.

Horizon North disclosed to the AUC that the power plant in question had been in operation since September 14, 2012, but that Horizon North was unaware of the regulatory requirements related to the operation of power plants.

The power plant consists of four 355-kilowatt natural gas turbines (a total of 1.42-megawatts), at Brion Energy Corporation's MacKay River facility, which provides power to the worker campsite. Horizon North noted that the turbines are operated in two units comprised of two turbines each, with only one unit capable of operation at a time. The remaining unit serves as an emergency backup.

Horizon North stated that the power plant is intended to be temporary, until a grid connection is available in late 2014, at which point, the power plant will be converted to emergency backup use.

Emission rates were noted as a possible concern, as emissions data was not available for the turbines in question. Comparable units that were slightly larger were noted as failing to meet the Alberta Air Emission Standards for Electricity Generation for nitrogen oxide (NOx) emissions. However, Alberta Environment and Sustainable Resource Development had not identified any concerns.

The AUC held that, in the absence of any identified concerns, and the temporary nature and small size of the power plant, which would be operated for Horizon North's sole use and consumption, that the power plant would be in the public interest.

Accordingly, the AUC granted a non-transferable exemption to Horizon North on the condition that Horizon North:

(a) Address any concerns of Alberta Environment and Sustainable Resource Development; and

(b) Not export energy to the Alberta Interconnected Electric System.

Alberta Electric System Operator – Egg Lake 2021S Substation Needs Identification Document; ATCO Electric Ltd. – Egg Lake Transmission Project Facility Application (Decision 2014-085)

The Alberta Electric System Operator ("AESO") applied for the approval of the Needs Identification Document ("NID") for the Egg Lake 2021S substation and a 144-kilovolt (kV) transmission line between the Egg Lake 2021S substation and the Kettle River 2049S substation.

ATCO Electric Ltd. ("ATCO") applied to construct and operate the Egg Lake 2021S substation and transmission line 7L177 and to alter the Kettle River 2049S substation.

No objections or concerns were raised by any stakeholders. The AESO submitted that the need for the facilities arose from industrial load growth. The proposed 33 kilometre 7L177 transmission line, was preferred by Alberta Environment due to lesser impact on caribou populations, and the use of existing disturbances.

The NID was approved pursuant to section 38(e) of the *Transmission Regulation*.

As there were no outstanding issues related to noise and consultation, and since ATCO's proposed mitigation measures concerning environmental effects were acceptable, the AUC found the facility application to be in the public interest.

Accordingly, the AUC approved ATCO's proposed facility and issued the related permits and licences to construct/alter and operate.

Alberta Electric System Operator – Timberlands 209S Substation Needs Identification Document; AltaLink

Management Ltd. – Timberlands Substation Transmission Development Facility Application; City of Red Deer – Timberland Substation Transmission Development Facility Application (Decision 2014-096)

The Alberta Electric System Operator ("AESO") filed a needs identification document ("NID") arising from the City of Red Deer's ("Red Deer") request for system access service. AltaLink Management Ltd. ("AltaLink") filed a facility application to alter the 768L and 788L 138-kilovolt (kV) transmission lines to accommodate the connection of Red Deer's proposed transmission lines. Red Deer filed a facility application for approval of the Timberlands 209S substation and transmission lines to connect the Timberlands 209S substation to the 768L and 788L 138-kV lines owned by AltaLink.

Red Deer had requested a transmission connection to address its growing energy demand. The AESO had determined that the construction of a 138/25-kV substation and a 138-kV transmission line would meet Red Deer's needs.

As there were no outstanding concerns or issues before the AUC, the AUC found that the applications were in the public interest, and issued the following approvals:

(a) Approval No. U2014-129 to the AESO for approval of the NID;

(b) Approval No. U2014-130 to Red Deer for the construction and operation of the Timberlands 209S substation;

(c) Permit and Licence No. U2014-131 to Red Deer for the construction and operation of Red Deer's portion of transmission line 768L;

(d) Permit and Licence No. U2014-132 to Red Deer for the construction and operation of Red Deer's portion of transmission line 464L;

(e) Permit and Licence No. U2014-133 to AltaLink for the construction and operation of AltaLink's portion of transmission line 768L;

(f) Permit and Licence No. U2014-134 to AltaLink for the construction and operation of AltaLink's portion of transmission line 464L;

(g) Salvage Approval No. U2014-135 to salvage a span of transmission line 768L;

(h) Connection Order No. U2014-136 to connect Red Deer's portion of transmission line 768L to AltaLink's portion of transmission line 768L; and

(i) Connection Order No. U2014-137 to connect Red Deer's portion of transmission line 464L to AltaLink's portion of transmission line 464L.

ATCO Electric Ltd. – Request for Review and Variance of DA2013-269 Alteration of an Access Road for Transmission Line 13L50 (Decision 2014-097)
Review and Variance – Access Road

This decision considered a request from Mr. Terry Symborski ("Symborski") to revoke the decision granted to ATCO Electric Ltd. ("ATCO") to change the location of an access road granted under approval DA2013-269 for the Eastern Alberta Transmission Line ("EATL").

Symborski submitted that he had no notice of the application or the decision to place an access road on his lands, and that Symborski had not consented to the access road being located on his lands. Symborski submitted that the access road would disrupt the construction and operation of three proposed gravel pits on his lands and, accordingly, also requested rescission or a suspension of Decision DA2013-269.

ATCO submitted that it had consulted with Symborski on October 2, 2013 in respect of the proposed access road, and sent Symborski a letter on October 28, 2013 advising that ATCO would be seeking a decision from the AUC. ATCO further submitted that the proposed gravel operations noted by Symborski were purely speculative in nature.

The AUC held that Symborski had rights which may be directly and adversely affected by the decision, including the right to sell gravel and other materials from his lands over which the proposed access road was to cross. Symborski therefore met the test for a review pursuant to sections 4(1) and 12(1)(b) of *AUC Rule 016: Review and Variance of Commission Decisions*.

The AUC accordingly granted Symborski's request for review and variance by extending the time limit for filing a review and variance under section 23(2) of the *Alberta Utilities Commission Act*. The AUC held that a time extension was appropriate on the basis that Symborski did not receive notice of the application, and was not provided with a copy of Decision DA2013-269.

The AUC found that there was a misunderstanding with respect to the outcome of the consultation between ATCO and Symborski, with ATCO believing that Symborski had not objected to the proposed access road. As a result of this misunderstanding, the original application proceeded by letter of enquiry and the decision was rendered without notice to interested parties and without a hearing.

The AUC suspended DA2013-269 pending a resolution of the issue pursuant to section 10(3) of the *Alberta Utilities Commission Act*.

NaturEner Wild Rose 2 Energy Inc. – Amendment to Wild Rose 2 Wind Power Plant (Decision 2014-099)
Amendment to Windfarm Approval – Turbine Change

NaturEner applied to alter the previously approved Wild Rose 2 wind power plant and requested a one-year extension to December 31, 2016, to complete construction of the power plant and the associated substation.

The proposed amendment consisted of a change of wind turbine model, from the approved Acciona AW-77 1.5 MW model to the Alstom ECO110 3.0-MW model due to the Acciona turbines no longer being produced. The Alstom turbines would have a wider rotor diameter (109.8 metres compared to 77 metres) and higher hub height (90 metres compared to 80 metres). The change in turbine would result in a:

- Reduced number of turbines from 108 to 63;
- Reduction in turbines located on native pasture from 19 to 12;
- Reduction in the project area from 8,351 hectares to 7,036 hectares; and
- Nameplate rated capacity increase from 162MW to 189MW.

As reported in the March 2014 issue of the Energy Regulatory Report, the AUC denied standing to all parties who filed submissions in response to the application for amendment. Accordingly, as there were no parties that filed submissions whose rights may be directly and adversely affected by the AUC's decision, the application for amendment was considered without a hearing.

The amendment to the power plant proposed a total mitigation plan of 143.38 hectares of finite-term conservation easement lands, to be selected in collaboration with the Fish and Wildlife division of the Alberta Environment and Sustainable Resource Development ("AESRD") representatives.

The AUC approved the extension request to December 31, 2016 for the construction of the power plant and substation.

The AUC considered that the approval of the amendment was in the public interest and therefore approved the application subject to the following:

(a) Pre-construction surveys must be carried out, as set out in the AESRD sign-off letter;

(b) A post-construction monitoring program acceptable to AESRD and the Canadian Wildlife Service must be developed;

(c) Filing of all studies and reports relating to the post-construction noise survey and the post-construction monitoring program with the AUC;

(d) Implementation of the proposed mitigation plan for native pasture; and

(e) A post-construction comprehensive noise study at the most impacted receptor to verify and ensure compliance with *AUC Rule 012: Noise Control* must be conducted.

Alberta Electric System Operator – Amendment to the Southern Alberta Transmission Reinforcement Needs Identification Document (Decision 2014-091)
NID Amendment – S. 38(e) Transmission Regulation

The Alberta Electric System Operator ("AESO") applied to remove Stage III from the approved needs identification document ("NID") for the Southern Alberta Transmission Reinforcement ("SATR") Approval.

Stage III consisted of a new transmission line connecting Ware Junction 132S substation to Langdon 102S substation. The AESO submitted that it had determined that Stage III would provide no material benefits on the southern transmission system, compared to the system configuration without Stage III.

TransCanada Energy Ltd. ("TCE"), concerned about transmission constraints, suggested that it would be more prudent to suspend the Stage III development rather than cancelling it entirely. Following further discussions with the AESO, TCE withdrew its statement of intent to participate.

The AUC approved the SATR NID amendment on the basis of s. 38(e) of the *Transmission Regulation,* which deems the AESO need to be correct, unless shown to be technically deficient or not in the public interest.

Alberta Electric System Operator and AltaLink Management Ltd. – Decision on Request for Review and Variance of AUC Decision 2013-369 re: Foothills Area Transmission Development (Decision 2014-093)
Use of existing infrastructure vs. new – TFO Delegation – Discrimination

Ronald and Laurie Conner, (the "Applicants"), applied for review and variance of the approval to amend the Southern Alberta Transmission Reinforcement ("SATR") needs identification document ("NID"). The NID amendment in question moved a portion of a new transmission line from an existing right of way to the Applicants' land. The reason for the change included the significant delay that would result from approvals required to use the existing transmission line right of way through the Piikani First Nation.

It was alleged that the original AUC decision included errors of law on the following issues:

1. Misinterpretation of ss. 15 and 15.1 of the *Transmission Regulation* – Whether due consideration was given to the use of the existing right of way.
2. Delegation to AltaLink Management Ltd. ("AltaLink") – Whether the Alberta Electric System Operator ("AESO") failed to subject AltaLink routing studies to any review or approval process; and
3. Failure to Apply Section 15(1) of the *Canadian Charter or Rights and Freedoms* ("*Charter*") – Whether the transmission route change to the new right of way resulted in "separate but equal" treatment of the Applicants and the Piikani First Nation and whether such treatment violated the equality right in s. 15(1) of the *Charter*.

The AUC denied the application for review and variance for the following reasons:

1. Sections 15 and 15.1 of the *Transmission Regulation*

   The AUC held that Decision 2013-369 properly interpreted and balanced ss. 15 and 15.1 of the *Transmission Regulation* because Decision 2013-369:

   - expressly stated that the AESO must consider maximizing the use of existing rights-of-way, but that the AESO must also plan a system that satisfies reliability requirements and is sufficiently robust so that electric energy can be dispatched without constraint; and
   - expressly considered temporary mitigation measures, but found they were not viable transmission planning solutions, and that it is not in the public interest to delay the line rebuild.

2. Delegation

   The AUC found there was no evidence that the AESO delegated the preparation of a part or all of the SATR NID amendment application to AltaLink, and specifically that Decision 2013-369 did not need to refer to this argument of the Applicants.

3. Section 15(1) of the *Charter*

   The AUC held that the Applicants failed to adduce evidence of discrimination. The evidence showed that the change in the transmission line and substation location was due to the potential for delay associated with the Peigan substation upgrades on federal lands which posed scheduling implications. Accordingly, the AUC found no breach of Section 15(1) of the *Charter* had been established.

Leave to Appeal Granted regarding AUC Decision 2013-025 (2014 ABCA 131)
Montana Alberta Tie – Leave to Appeal

The Montana Alberta Tie ("MATL") was authorized by the National Energy Board in 2007 and the predecessor of the AUC in 2008 (Alberta Energy Utilities Board Decision 2008-006) and has since been completed and energized.

In order to accommodate MATL in the Alberta Interconnected Electric System ("AIES"), the Alberta Electric System Operator ("AESO") proposed a rule for managing transfer capability on the AIES: Section 203.6 of the ISO Rules, *Available Transfer Capability and Transfer Path Management* (the "Proposed Rule").

Existing stakeholders filed numerous objections to the Proposed Rule. Those objections were heard by the AUC and eventually dismissed in Decision 2013-025 (the "Initial Decision").

The AUC denied an application for review and variance finding that the applicants had not demonstrated substantial doubt regarding the correctness of the impugned decision in Decision 2013-305 (the "Review Decision").

In five separate applications for leave to appeal, Saskatchewan Power Corporation, Northpoint Energy Solutions Inc., ATCO Power Ltd., Powerex Corp., British Columbia Hydro and Power Authority and TransCanada Energy Ltd. sought to obtain leave to appeal the Initial Decision and TransCanada Energy Ltd. sought leave to appeal the Review Decision of the AUC.

The test for leave to appeal includes the following criteria:

1. Whether the point is of significance to the practice;
2. Whether the point is of significance to the action itself;
3. Whether the proposed appeal is *prima facie* meritorious; and
4. Whether the appeal will unduly hinder the progress of the action.

The applications were heard together. Ten grounds of appeal were proposed to challenge the correctness of the Initial Decision and four to challenge the Review Decision.

The Alberta Court of Appeal concluded that two of the proposed grounds raised to challenge the Initial Decision satisfy the criteria for granting leave to appeal. Leave to appeal was granted on the following questions:

(a) Whether the AUC erred in law in its interpretation of s. 16 and/or s. 27 of the *Transmission Regulation*; and

(b) Whether the AUC erred in law in its interpretation of s. 29 of the *Electric Utilities Act* by finding that the AESO is required by statute to provide system access service to intertie operators.

Leave to appeal on the Review Decision was denied because:

(a) To the extent that certain grounds are addressed in the leave granted to appeal the Initial Decision, appeal of the Review Decision becomes moot; and

(b) Other grounds lacked merit.

Alberta Electric System Operator Round Hill 852S Substation Upgrade – Needs Identification Document – AltaLink Management Ltd. Round Hill 852S Substation Upgrade – Facility Application (Decision 2014-098)

The Alberta Electric System Operator ("AESO") requested approval of the need for an upgrade to the Round Hill 852S substation and AltaLink Management Ltd. ("AltaLink") requested approval to alter and operate the Round Hill 852S substation by adding one 25-kV switchgear building and adding two new 25-kV circuit breakers.

No interested party demonstrated that the AESO's assessment of the need to upgrade the substation was technically deficient or that approval of the NID application was not in the public interest. No incremental audible noise will arise from the substation upgrade. There were no outstanding public or industry objections or concerns.

Accordingly, the AUC approved the need application and the facility application and granted the Substation Permit and Licence. The AUC expects AltaLink to continue to consult with Alberta Environment and Sustainable Resource Development regarding the caribou protection plan for this project.

ENMAX Power Corporation Formula-Based Ratemaking Transmission Tariff Re-opener (Decision 2014-100)
FBR – Transmission Reopener – G-Factor – X-Factor

ENMAX Power Corporation ("ENMAX") applied to the AUC for a re-opening of its formula-based ratemaking ("FBR") plan as it relates to transmission tariffs in AUC Decision 2009-035 approved for the period of 2007-2013. That decision allowed ENMAX to apply to re-open its transmission tariffs for remedial adjustments as a safeguard after the occurrence of specified thresholds. One such threshold was if ENMAX's PBR plan had a return on equity ("ROE") that was 300 basis points below the target ROE for two consecutive years, or 500 points below the target ROE for one year.

ENMAX applied to the AUC for a re-opening of its transmission tariffs for changes to the growth factor ("G-Factor") and productivity factor ("X-Factor") components of its FBR plan. ENMAX requested that the X-Factor be reduced from 1.2 to 0.0 for 2013, and that the G-Factor be amended to eliminate the lag in the recovery of the G-Factor amounts. As a result, ENMAX requested approval to recover a total of $20.45 million from the Alberta Electric System Operator ("AESO") as a one-time invoice.

After the AUC approved a re-opening of the ENMAX FBR plan in Decision 2013-399, the current hearing was held to determine whether there was evidence of a structural issue with the FBR plan that would operate to deny a company a reasonable opportunity to recover its prudently incurred costs and a reasonable return on investment. The AUC held that a remedy should not be approved if the discretionary actions of ENMAX, and not the structure of the FBR plan, caused the financial circumstances that triggered the re-opener.

G-Factor

ENMAX submitted that interested parties were aware that the rates under the G-Factor could be subject to change, as contemplated by the re-opener and, as such, did not violate the prohibition on retroactive rate-making. Intervenor groups submitted that rates established between 2007 and 2009 were set on a final basis and therefore not subject to change.

The AUC denied ENMAX's request to amend the G-Factor for 2007-2009, as those rates were considered final, and the G-Factor was not a true deferral account. The AUC allowed revisions to the G-Factor for 2010-2013 on the basis that all parties were aware of, and did not object to ENMAX's request for the AUC to not finalize rates until a decision was rendered on its re-opener application.

ENMAX submitted that due to the higher than forecast contributions in aid of construction and a lag in collecting such revenue under FBR, the G-Factor did not generate sufficient revenue to provide a reasonable return. The AUC found significant increases in capital additions well above forecast levels beginning in 2010. The AUC also found that the existing G-Factor was unable to allow for the recovery of revenue requirement related to transmission capital expenditures. The existing G-Factor calculation was:

$$G = (Mid\ Year\ Base) * [WACC + Depreciation\ Rate]$$

The AUC held that modifications to the G-Factor were necessary, and directed that ENMAX's revised G-Factor be calculated as follows, using 2010 as an example year:

$$(GFactor)_{2010} = (Capital\ related\ revenue\ requirement)_{2010} - (Revenue\ from\ I - X\ mechanism)_{2010}$$

Where:

$$(Revenue\ from\ I\text{-}X\ mechanism)_{2010} = (Capital\text{-}related\ revenue\ requirement)_{2006\ approved\ going\text{-}in\ rates} \times [1+(I - X)_{2007}] \times [1+(I - X)_{2008}] \times [1+(I - X)_{2009}] \times [1+(I - X)_{2010}]$$

and:

"Capital-related revenue requirement" is the depreciation, interest and return (at the approved ROE) on the full transmission rate base of ENMAX in the year indicated.

ENMAX was directed to recalculate earnings sharing for 2010 to 2013 using the above formula, and bill to the AESO as a one-time adjustment. The AUC ordered that ENMAX submit a compliance filing to reflect the revisions to the G-Factor for the years 2010 through 2013.

X-Factor

ENMAX also sought to reduce its X-Factor to 0.00 for 2013, as its planned X-Factor of 1.2 was not achievable under its current circumstances of slowed productivity and staff additions related to operations, maintenance and administration ("OM&A") requirements. However, intervenor groups noted that if the G-Factor was corrected, any change to the X-Factor would give ENMAX an ROE above its approved ROE from 2007 to 2013, with the exception of 2012.

As ENMAX had not conducted any productivity studies, the AUC held that there was insufficient evidence to demonstrate a need to change the X-Factor. The AUC also held that X-Factors were set at the beginning of the tariff term to encourage companies to seek cost efficiencies, and would lose its incentive if a company could simply apply to change the X-Factor. The request to change the X-Factor was therefore denied.

Shell Canada Ltd. – Two-MW Power Plant Exemption (Decision 2014-101)
Sole Use Exemption

The AUC granted a non transferable exemption from Section 11 of the *Hydro and Electric Energy Act,* subject to the following conditions:

(a) The power plant be built and located as described in the application;

(b) The power plant not export energy to the Alberta Interconnected Electric System; and

(c) Compliance with the noise requirements of AUC *Rule 012*.

ATCO Gas 2014 Performance-Based Regulation Application – Compliance Filing Adjustment to Proposed Irrigation Rate (Decision 2014-102)
PBR – Irrigation Rate – Carbon Rider

ATCO Gas, a division of ATCO Gas and Pipelines Ltd., ("ATCO") applied for approval of an adjustment for the irrigation rate group under Rider I as approved in Decision 2012-113, to be effective May 1, 2014.

ATCO had originally applied for a 2014 performance based regulation ("PBR") rate adjustment to include the remainder of its Carbon Rider reconciliation shortfall through an adjustment to irrigation rates. The shortfall amount remaining was noted as $275,402. Due to the limitations imposed by Decision 2013-460 respecting 2014 rate increases, ATCO proposed to collect $133,148 of the shortfall amount in 2014, and proposed to collect the remainder in its 2015 PBR rate adjustment application. ATCO submitted that this would comply with the rate increase cap of 10 per cent for each year.

The AUC found that the revised calculations for the Carbon Rider reconciliation variable rate conformed to principles of rate stability and complied with the AUC's directions in Decision 2013-460. The AUC approved the adjustment of $0.633/gigajoule (GJ) bringing the total variable rate for the irrigation rate group to $1.750/GJ.

The AUC approved the adjusted irrigation rates for ATCO, effective May 1, 2014, but the AUC declined to approve the 2015 rate adjustments, deferring it to ATCO's 2015 PBR rate adjustment application.

Compton Petroleum Corporation – 16.5-MW Natural Gas-fired Power Plant (Decision 2014-103)
Construction and Operation – Connection Order

The AUC found that the air emissions from the project are expected to be compliant with the Alberta Ambient Air Quality Objectives and that the power plant will not exceed the permissible sound level. Accordingly, the AUC approved the application to construct and operate and issued the Connection Order.

Mustus Energy Ltd. Time Extension to Complete the Construction of a 41.5-MW Biomass Power Plant (Decision 2014-104)

Mustus Energy Ltd. ("Mustus") applied for a time extension from March 31, 2015 to December 31, 2016 to complete construction of a 41.5-megawatt (MW) biomass power plant.

Mustus submitted that it required additional time due to delays while Alberta Environment and Sustainable Resource Development reviews the Diversion of Biomass to Energy from Biomass Combustion Facilities offset protocol (the "Protocol"). Implementation of the Protocol is a condition of financing for the biomass power plant. The AUC approved the requested time extension.

Alberta Electric System Operator Sweetheart Lake 2032S Substation Needs Identification Document; ATCO Electric Ltd. Sweetheart Lake 2032S Substation Facility Application (Decision 2014-106)

The Alberta Electric System Operator ("AESO") applied for the approval of the Needs Identification Document ("NID") for the construction of a 144/25-kilovolt (kV) substation to be named the Sweetheart Lake 2032S substation, and to connect it to the Alberta Interconnected Electric System ("AIES"). The application arose from a request from Japan Canada Oil Sands Limited to serve a 25-megawatt (MW) industrial load increase in the Fort McMurray area.

ATCO Electric Ltd. ("ATCO") applied for approval to construct and operate the Sweetheart Lake 2032S substation, and to construct an 8 kilometer, 144-kV transmission line to connect the Sweetheart Lake 2032S substation to the AIES, to be named transmission line 7L147.

No objections or concerns were raised by any stakeholders. The AESO submitted that the construction of a new transmission line and substation was the only option that met the minimum planning guidelines for distribution operating voltages. ATCO submitted that the proposed transmission route was selected as it travelled through the least amount of new linear disturbance, the shortest lengths through riparian and muskeg areas, and overall was the shortest of the three options considered.

Alberta Environment and Sustainable Resource Development ("AESRD") did not express any concerns, as ATCO had worked closely with AESRD to mitigate the environmental impacts of the transmission line and substation construction.

Among the impacts addressed, ATCO submitted that it would use anti-perch devices at substations, and avoid routing lines through high avian usage areas. ATCO also committed to monitor the transmission line and substation to assess avian impacts to determine whether any additional mitigation is necessary.

The AUC held that the environmental impacts of the construction of a transmission line and substation would be adequately mitigated by ATCO, and held that the application complied with noise requirements and the Lower Athabasca Regional Plan. Accordingly, the AUC approved the AESO's NID and issued to ATCO the related permits and licences.

ATCO Electric Ltd. – Decision on Request for Review and Variance of Decision 2012-303: Eastern Alberta Transmission Line (Decision 2014-107)
Time Limits for Review and Variance – Criteria for Review beyond Time Limits – Jurisdiction re: Compensation

The applicant, whose land is crossed by the Eastern Alberta Transmission Line ("EATL"), sought an order for an oral hearing to decide if ATCO Electric Ltd. ("ATCO Electric") had met the commitments made by ATCO Electric prior to the issuance of the AUC's EATL decision. The application is based upon alleged new facts and ATCO Electric's refusal to offer a buy out or other compensation to the applicant.

The AUC denied the application for review because the applicant did not establish that exceptional circumstances exist that would warrant a review of the EATL decision more than one year after that decision was issued.

Even if the application had been filed within the time limits prescribed in *Rule 016*, the AUC would have dismissed their application because the review request did not raise an error of fact.

The AUC also found that it had no jurisdiction to direct ATCO Electric to offer a buy out or pay the applicant compensation because that is within the exclusive jurisdiction of the Surface Rights Board.

Blaze Energy Ltd. – Application for an Exemption under Section 24 of the Hydro and Electric Energy Act (Decision 2014-108)
Electric Distribution System Exemption – Test for Public Highway

Blaze Energy Ltd. ("Blaze") applied for an exemption under Section 24 of the *Hydro and Electric Energy Act* to own and operate a 6.9-kilovolt (kV) distribution line between its Brazeau and Wild Rose gas plants, currently owned by Fortis Alberta, but not yet energized.

Electricity is delivered to the Brazeau plant directly from the Alberta Interconnected Electric System. Fortis provides demand transmission service for Blaze and Blaze is billed as a Rate 65 service.

Fortis indicated that it had no objections to Blaze owning and operating the distribution line between the gas plants if either the two plants operate within an industrial system designation, or an exemption pursuant to Section 24 if the *Hydro and Electric Energy Act* is granted by the AUC.

As the distribution line is a 6,900-volt line, it cannot meet the voltage limitation of Section 24(1)(b) . Therefore, in order to obtain the exemption, the requirements of Section 24(1)(a) must be met.

There are two components to the exemption found in Section 24(1)(a). Firstly, an applicant must demonstrate that it is proposing to distribute electric energy solely on land of which the applicant is the owner or tenant for use on that land. Secondly, the applicant must not be seeking to distribute electric energy across a public highway. As a leaseholder of Crown land leases, Blaze met the first component of the Section 24(1)(a) requirement.

The plot plan and survey land map submitted, however, showed that the distribution line crossed a road allowance. Although the government road allowance is not currently in use, it has been surveyed for use, which the AUC found was sufficient to constitute a public highway. Accordingly, the AUC denied the exemption.

Alberta Electric System Operator, Capital Power Corporation, TransAlta Corporation and TransCanada Energy Ltd. – Application for review of AUC Decision 2012-104: Complaint by Milner Power Inc. ("Milner") regarding the ISO Transmission Loss Factor Rule and Loss Factor Methodology (Decision 2014-110)
Line Losses – Methodology – Review and Variance

On April 16, 2014 the AUC rendered *Decision 2014-110* (the "*2014 R&V Decision*"), upholding the findings in AUC Decision 2012-104 ("Decision 2012-104") that the Independent System Operator ("ISO") Rule 9.2: *Transmission Loss Factors* and Appendix 7: *Transmission Loss Factor Methodology and Assumptions* (collectively, the "2005 Line Loss Rule"):

(a) Did not comply with Section 19(1)(a) and Section 19(2)(d) of the 2004 *Transmission Regulation* (the "*2004 T-Reg*"); and

(b) Was inconsistent with or in contravention of Section 25(6)(b) of the 2003 *Electric Utilities Act* (the "*2003 EUA*") by being unjust, unreasonable, unduly preferential, arbitrarily or unjustly discriminatory.

In confirming these findings, the AUC determined that the 2005 Line Loss Rule did not assign to each generating unit a line loss charge or credit:

(a) Based on each generating unit's overall contribution (either positive or negative) to total line losses on the Alberta Interconnected Electric System; and

(b) That is representative of each generating unit's impact on average system losses relative to load.

The AUC held that the 2005 Line Loss Rule loss factor methodology (referred to as MLF/2), did not attribute to line loss savers the full measure of savings they were responsible for having created. This resulted in the loss factors that were assigned to loss causers being lower than they would otherwise have been given the losses they created. This violated principles of cost causation by arbitrarily distributing some loss savings to loss causers who have not contributed to such loss savings. Accordingly, MLF/2 has systematically under collected the costs of line losses attributable to cost causers and under compensated or over collected losses from line loss savers.

<u>Rescission in Part</u>

The *2014 R&V Decision* rescinded, in part, *Decision 2012-104,* which held in:

(a) Paragraph 6, that the 2005 Line Loss Rule as it exists today did not support the fair, efficient and openly competitive operation of the market and was not in the public interest;

(b) Paragraph 116, that an incremental loss factor methodology and not the marginal loss factor methodology was what did comply with the *2004 T-Reg* and *2003 EUA*; and

(c) Paragraph 120, that because the 2005 Line Loss Rule was not economically efficient under the new standard of review, Milner's complaint would have also been valid, were it complaining about the line loss rule post 2008.

<u>2005 Line Loss Rule Impacting Market</u>

In its decision the AUC held that the manner in which line loss costs are determined and assigned to each generating unit have a bearing on competitive market outcomes, because the cost of line losses payable by generators impact calculation of their offer prices. The 2005 Line Loss Rule diminished the competitive advantage (in terms of lower line loss costs) that would otherwise accrue to generating units making efficiency-enhancing locational decisions.

The 2005 Line Loss Rule was inconsistent with achievement of the objective in Section 5(c) of the *2003 EUA* in that it resulted in unfair advantages being conferred upon one set of generating units (line loss causers) relative to other generating units (line loss savers), thereby distorting the market for electricity and the structure of the Alberta electric industry.

<u>Findings About Loss Factor Collection Compliant with Legislation</u>

The AUC made determinations about line loss factors that will be compliant with Section 19(1)(a) and Section 19(2)(d) of the *2004 T-Reg* and not be inconsistent with or in contravention of Section 25(6)(b) of the *2003 EUA*. This would be the case when loss factors:

(a) Were representative of the impact of a generating unit on average system losses; and

(b) Reasonably recovered a generating unit's contribution to transmission line losses.

In considering what constitutes a generator's "contribution" to line losses under Section 19(1)(a) of the *2004 T-Reg,* one has to establish the extent, if any, to which each generating unit added to or lowered total system line losses over the full range of its output over the time period under consideration.

AESO's Duties re Operating Market

The AUC emphasized the AESO's duties related to operation of the market, including the AESO's duty under Section 17 of the 2003 *EUA* to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy.

Proceeding to Phase 2

The AUC directed proceeding with the second phase of its consideration of Milner's complaint to determine the relief or remedy to be given.

The City of Medicine Hat – Transmission Line MH-10L Upgrade Project (Decision 2014-112)
Medicine Hat – Upgrades

The City of Medicine Hat ("Medicine Hat") applied to upgrade a portion of the Medicine Hat transmission system from 69-kilovolt (kV) to 138-kV by:

(a) Construction of a new 138/69-kV substation to be named MHS-8;

(b) Alteration of the existing MH69S-2 substation which would be redesignated MHS-2; and

(c) Upgrade of a portion of transmission line MH-10L from 69-kV to 138-kV.

The applications arose from forecast transmission deficiencies. Medicine Hat submitted that it was unable to effect the upgrade simply by altering existing substations, due to a lack of available space in the MH69S-6 substation. Accordingly, Medicine Hat proposed that the MH-10L transmission line be reconstructed between the MHS-8 and MH69S-2 substations as a 138-kV line, and that the remaining 69-kV portion of the MH-10L transmission line be redesignated as MH-12L.

The AUC found that the application complied with all technical, environmental and noise requirements, and noted that there were no outstanding public or industry objections or concerns. The AUC therefore granted the application by issuing the related permits and licences.

Pivot Data Centres Inc. – 4.0-MW Standby Generators (Decision 2014-113)
Sole Use Exemption

Pivot Data Centres Inc. applied to install a 4.0-MW power plant.

The AUC granted a non-transferable exemption from Section 11 of the *Hydro and Electric Energy Act*, on the following conditions:

(a) The power plant be located and built as described in the application;

(b) The power plant not export energy to the Alberta Interconnected Electric System; and

(c) Compliance with the noise requirements of AUC *Rule 012*.

Alberta Electric System Operator – Engstrom to Kinosis Transmission Line and Substation Upgrades Needs Identification Document; ATCO Electric Ltd. – Engstrom to Kinosis Transmission Project Facility Application (Decision 2014-114)

The Alberta Electric System Operator ("AESO") applied for approval of need, and ATCO Electric Ltd. ("ATCO) applied for approval to construct and operate the following:

(a) 15 kilometers of 144-kilovolt (kV) transmission line to be designated 7L183, connecting the Engstrom 2060S substation with the Kinosis 856S substation;

(b) One 240/144-kV transformer and other equipment to the Kinosis 856S substation; and

(c) Two circuit breakers to the Engstrom 2060S substation.

The need arose from a request for transmission system access for the Conoco Phillips Canada Surmont 2 facility, of which the first two of the three stages had already been approved by the AUC.

ATCO considered two routes to complete the transmission line, but selected the west route because it followed more existing disturbances and had greater support among stakeholders consulted.

ATCO committed to perform construction during winter conditions to avoid and mitigate impacts to migratory birds and environmentally sensitive areas.

The AUC found that there were no outstanding technical, routing, environmental or noise concerns associated with the facility applications or the needs identification document. Accordingly, the AUC approved the applications and issued the related permits and licences.

1646658 Alberta Ltd. Bull Creek Wind Project Costs Award (Decision 2014-116)
Cost Award

This costs decision arises out of the participation of Killarney Lake Group ("KLG") in a hearing from an application brought by 1646658 Alberta Ltd. ("BluEarth") a wholly owned subsidiary of BluEarth Renewables Inc. to construct and operate the Bull Creek Wind Project.

KLG had received advanced funding approved by the AUC in Decision 2013-026 in the amount of $142,109.50 based upon forecasted fees of $306,155. KLG submitted a local intervener costs final claim application for $861,220.49.

BluEarth objected to the costs claimed, indicating that they were unreasonable, greatly exceeded estimates, and that the experts testifying on behalf of KLG were not objective, thereby unnecessarily lengthening the hearing.

The AUC found that the costs submitted by Ackroyd LLP, while considerable, were directly and necessarily related to the hearing. The AUC noted that the proceeding was novel, in that it considered certain issues for the first time. The AUC also held that the coordination of information requests, responses, cross-examination of seven expert witnesses, and the coordination of 11 expert witness submissions and 25 local intervenors were all factors that weighed in favour of granting the costs claimed by Ackroyd LLP. The AUC therefore held the majority of these costs were reasonable.

The AUC found the consulting fees of Cottonwood Consultants Ltd., Sweetgrass Consultants Ltd., FDI Acoustics Inc., Dr. Hanning, Dr. Upton, Hydrogeological Consultants Ltd., and Mr. James to be reasonable, and that their participation in the hearing contributed to a better understanding of the issues.

The AUC reduced consulting fees for Gettel Appraisals Ltd., Dr. Phillips, and Dr. Rhodes/Kylene Power Ltd. by 15%, 30%, and 40% respectively on the basis that some of the work had been duplication or adaptation of previous studies submitted to the AUC in other proceedings, or because the evidence provided either did not assist the AUC in its understanding of the issues or unnecessarily lengthened the hearing.

The AUC also denied several honoraria requests for several of the individual members of KLG, as some costs, such as costs for feeding cattle and lost wages are not contemplated by AUC *Rule 009: Scale of Costs*.

The AUC ordered BluEarth to pay interevener costs in the total amount of $649,003.86 to KLG.

AUC Rule 007 – Application for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments (AUC Bulletin 2014-06)

The AUC approved changes to *Rule 007* with an effective date of April 1, 2014. The approved changes and related material are posted on the AUC's website under the tab Rule Development.

New Gas Utility Pipelines Need Assessment (AUC Bulletin 2014-08)

The AUC, following input from stakeholders, revised the need assessment for new gas utility pipelines by incorporating more clearly defined requirements and procedures.

The basic requirements and procedures for the assessment of need are as follows:

<u>Basic Requirements</u>

1. Need includes:
   - Project justification;
   - Project cost;
   - Identification of alternatives and associated costs;
   - Assessment of the implications of the alternatives on the public and the environment; and
   - Rationale for selecting the applied-for project including an economic evaluation comparing the alternatives.

2. Sufficient information must be provided by the applicant such that the permit and licence issued by the AUC can describe where, when and how the need has been established and include reference to the estimated project cost.

3. Projects that are part of a larger, integrated program should be identified and reviewed as part of that larger program to ensure that the AUC has a full understanding of the program scope and implications.

4. Directly impacted persons must have an opportunity to understand the project impact, have their concerns addressed by the applicant, or heard by the AUC if not addressed by the applicant.

5. Rates associated with gas utility pipeline facilities may be considered and established on a prospective basis with a subsequent true-up process to ensure that the projects entering rate base are used and required to be

used and that only prudently incurred costs enter rate base.

Procedures

1. Need will be addressed, to the extent practical, in the first instance an applicant files a gas utility pipeline capital project proposal with the AUC, either as part of a general rate application ("GRA"), a facility application, or as part of a capital tracker application for companies that may be operating under performance-based regulation.
2. Streamlined or abbreviated need assessment processes will be permitted for certain gas utility pipeline projects that meet defined thresholds.
   - New growth and replacement projects that meet defined dollar and physical attribute thresholds and are unlikely to have significant landowner or environmental impacts.
3. Growth projects identified in the NOVA Gas Transmission Ltd.-ATCO Pipelines integration arrangement that are currently administered in a deferral account process will continue to be administered in this way. Deferral accounts for other projects are not currently contemplated.
4. The AUC will reserve the right to defer approval of the need for projects from a GRA to a facilities application (e.g. where there are expected landowner or environmental issues).
   - GRA decisions will state whether the need for a project has been approved or deferred.
5. Where the need is approved in a GRA, the cost estimate will form the basis of the variance/prudence assessment that occurs at the time of the next GRA (opening rate base), unless the estimate is subsequently modified through the facility application process.
   - Where the cost estimate associated with need is approved as part of the facilities application, this cost estimate will be considered in the subsequent prudence assessment, at the time of the next GRA, when establishing an opening rate base amount.
6. Projects that were not included in a GRA filing will have the need assessed in the facility application for a permit and licence.
   - If the gas utility pipeline owner files an application for a permit and licence for a project where the need was not previously assessed and approved in the GRA, or before the GRA decision is issued, the need aspect of that project will be dealt with in the facility application process instead of the GRA; and
   - The facility owner should identify where the need has been dealt with in its facility application.

The AUC will provide further details of these basic requirements and procedures at a later date and provide stakeholders with the opportunity to provide comments.

Streamlining the debt application process for utilities (AUC Bulletin 2014-09)
Debt applications

The AUC has posted a minimum filings guideline on its website intended to assist utilities in identifying the necessary information to include in their applications. Additionally, the amount of time allowed to file a statement of intent to participate ("SIP") in a debt application proceeding has been reduced from two weeks to one week.

The minimum filing guidelines set out below are based upon the AUC's obligations in Section 101(2)(a)(ii) of the *Public Utilities Act* and Section 26(2)(a) of the *Gas Utilities Act.*

The minimum filings for debt applications require the utilities to:

1. Substantiate the purpose of the issuance;
2. Provide a legal opinion confirming that all required corporate governance authorizations for the issuance of the debt have been obtained and that debt may be legally incurred by the utility;
3. Provide a resolution of the applicant's board of directors authorizing the creation of debt, specifying the date on which the resolution was passed;
4. Provide the principal amounts and corresponding maturity dates;
5. Provide the terms and conditions of the debt such as estimates of the time of issuance, interest rate per annum, and any other relevant details;
6. In the case of an intercompany issuance, provide details of the entity going to the market, the estimated time of issuance, the amount of debt to be raised in the market, the coupon rates for that debt, the corporate structure through which the issuance flows through to the utility and the coupon rates that will be applicable to the utility; and
7. Provide the distribution of the issuance, if any, between various functions of a utility (i.e. distribution and transmission) or between utility affiliates.

NATIONAL ENERGY BOARD

Triton LNG Limited Partnership – Application for a Licence to Export Liquefied Natural Gas
LNG Export Licence – Filing Exemption – Reporting Exemption

The NEB issued a licence to Triton LNG Inc. on behalf of Triton LNG Limited Partnership ("Triton"), for export at Kitimat or Prince Rupert, B.C. The licence is for a term of 25 years with a 10 year sunset clause and a 15% annual tolerance.

The NEB exempted Triton from the filing requirements contained in section 12 of the *Oil and Gas Regulations*, but the NEB denied Triton's request for exemption from the *Reporting Regulations*.

Nova Gas Transmission Ltd. – Request for Variance of Order SG-N081-001-2014 Approved with Additional Conditions
Safety – Review and Variance – Pressure Restrictions

As reported in the March Issue, NEB Safety Order SG-N081-001-2014 (the "Order"), imposed a 20% pressure reduction on 25 pipelines. The NEB has issued Amending Order AO-002-SG-N081-001-2014 (the "Amending Order"). The Amending Order was issued in response to the review and variance request filed by Nova Gas Transmission Ltd. ("NGTL") on March 28, 2014 to vary some of the pressure restrictions imposed by the NEB in the Order (the "Variance Request").

In the Amending Order, the NEB approved the Variance Request but imposed additional conditions requiring heightened monitoring and leak detection activities. The Amending Order differentiates the pipelines affected by the Order into four schedules, as indicated below:

1. Schedule A includes pipelines for which the pressure restrictions in the Order pose public safety concerns because they would result in loss of gas supply to certain utilities. The pipelines in Schedule A are subject to the following conditions requiring TransCanada PipeLines Limited ("TCPL") to:

   (a) Before December 31, 2014, conduct: (i) the appropriate in-line inspection ("ILI") for the susceptible hazard(s); (ii) subsequent excavations to validate the ILI; and (iii) any applicable mitigation of the hazard(s) identified from the ILI results;

   (b) Before December 31, 2014, conduct a hydrotest if the requirements in condition (a) are unable to be completed;

   (c) Provide an Engineering Assessment to the NEB that demonstrates the line is fit for continued service by December 31, 2014;

   (d) Before July 31, 2014, and only for the portions of the pipeline with the highest societal risk, conduct Direct Assessments for the applicable hazard(s) in compliance with the appropriate NACE Direct Assessment Standard Practice ("NACE DA SP") for the relevant hazard(s);

   (e) By July 31, 2014, provide a letter to the NEB confirming that the Direct Assessment and the Engineering Assessment have been completed; and

   (f) Until condition (c) is satisfied, conduct appropriate monthly leak detection on the entire pipeline.

2. Schedule B includes pipelines for which the 20% pressure reduction in the Order would result in impacts on transportation services. The pipelines in Schedule B are subject to the following conditions requiring TCPL to:

   (a) Before September 1, 2015, conduct: (i) the appropriate in-line inspection ("ILI") for the susceptible hazard(s); (ii) subsequent excavations to validate the ILI; and (iii) any applicable mitigation of the hazard(s) identified from the ILI results;

   (b) Before September 1, 2015, conduct a hydrotest if the requirements in condition (a) are unable to be completed;

   (c) Provide an Engineering Assessment to the NEB that demonstrates the line is fit for continued service by September 1, 2015.

   (d) Before December 31, 2014, and only for the portions of the pipeline with the highest societal risk, conduct Direct Assessments for the applicable hazard(s) in compliance with the appropriate NACE DA SP for the relevant hazard(s).

   (e) By December 31, 2014, provide a letter to the NEB confirming that the Direct Assessment and the Engineering Assessment have been completed.

   (f) Until condition (c) is satisfied, conduct appropriate monthly leak detection on the entire pipeline.

The pressure restrictions will remain in effect until the NEB is satisfied that the NGTL pipelines identified can be operated safely and in a manner that protects people and the environment at an increased pressure.

Schedule C includes the pipelines for which TCPL did not request any variance. Schedule D includes pipelines that were not in service or already operating as a low pressure distribution line.

<u>Summary of Schedules</u>

	Facility	Licensed MAOP	90 Day High Pressure ending Mar.4/14	Reduced MAOP
Schedule A				
1	Suffield South Lateral	8475	5286	5286
2	Unity Lateral	7068	5879	5879
3	Donalda Lateral	8380	6251	5938
Schedule B – Pressure Reduction of 5% or 10% below 90 Day High Pressure (as Specified)				
1	Bassano South Lateral	8275	5955	5657
2	Wildcat Hills Lateral	6516	5700	5415
3	Quirk Creek Lateral	6736	5818	5527
4	Sylvan Lake Lateral	6517	5967	5669
5	Nevis Lateral	7068	6155	5847
6	Robb Lateral	6895	5865	5572
7	Minnehik Buck Lake Lateral Loop	6386	6248	5623
8	Crossfield Lateral Loop	6517	5478	5204
9	Crossfield Lateral	6516	5478	5204
10	Cutbank River Lateral	8290	7075	6367
Schedule C – Pressure Reduction of 20% below 90 day High Pressure – No variance requested				
1	Eastern Alberta System Mainline Empress to Princess Loop 3	5695	4634	3707
2	Waterton Lateral	6516	6266	5013
3	Waterton Interchange Lateral	7446	5323	4258
4	Ricinus Lateral	7448	6000	4800
5	East Lateral Loop	6280	4806	3845
6	Alderson Lateral	6737	6220	4976
7	Atmore Lateral	8462	7326	5861
8	September Lake Lateral	8455	7548	6038
9	North Lateral Extension Stage 1 Brooks	8450	5690	4552
10	Ferrier North Lateral	6282	6178	4942
Schedule D – No additional Pressure Restriction Required				
1	Kaybob South Lateral	6248	Nil	Not applicable; line is currently out of service pending repair and submission of Environmental Assessment per Order
2	Carstairs Lateral Sales	6206	690	Not applicable; line is operated at low pressure

TransCanada PipeLines Limited – Engineering Evaluation for Line 100-4 Temporary Pressure Reduction Relaxation (Order SG-T211-002-2014)
Safety Order – Pressure Reduction Relaxation – Engineering Assessment

TransCanada PipeLines Limited ("TCPL") filed an Engineering Evaluation in support of a request for relaxation of temporary pressure reduction for Line 100-4 to 5400kPa for the purpose of conducting inline inspections (the "Request"). The Request related to the October 23, 2013 Incident 2013-150, which occurred on the TCPL Canadian Mainline Line 100-4 at MLV 2 near Burstall, Saskatchewan.

The NEB determined that TCPL's Engineering Evaluation did not meet the requirements for an engineering assessment as outlined in CSA Z662-11 Clause 3.3 and 10.3 and did not demonstrate that the section of Line 100-4 between Mainline Valves 2-4 and 9-4 ("Line 100-4 MLV 2-4 to 9-4") is fit for service at 5400 kPa.

The NEB ordered four safety measures, pursuant to sections 12 and 48 of the *National Energy Board Act*, one of which being an operating pressure restriction for Line 100-4 MLV 2-4 to 9-4 of 3500 kPa.

The Board noted the importance of inline inspections, however emphasized that the decisions to conduct such inspections must be based on evidence that it is safe to do so, or that a company is able to mitigate the risks involved.

TransCanada PipeLines Limited – Application to Participate in NEB Public Hearing for 2015-2030 Tolls
NEB Public Hearing

TransCanada PipeLines Limited ("TransCanada") has applied for approval of the 2013-2030 Settlement Agreement between Union Gas Limited, Enbridge Gas Distribution Inc., Gaz Métro Limited Partnership and TransCanada.

The application proposes tolls for the 2015 through 2020 period and provides a methodology for calculation of tolls for the 2021 to 2030 period. The application also provides for certain new services to be offered by the Mainline.

The NEB determined to hold a public hearing. Those who wish to participate in the hearing must apply to participate.

The NEB has identified the following as a non exhaustive list of issues to be addressed in the hearing:

1. Appropriateness of the proposed toll design for 2015-2020, including the consideration of the toll adjustment methodology, and allocation and treatment of the Long Term Adjustment Account and Toll Stabilization Account.
2. Appropriateness of the proposed revenue requirements and rate base over the 2015-2020 term including assumptions regarding costs, billing determinants and revenues.
3. Appropriate allocation of risk and reward among TransCanada, Mainline shippers and other stakeholders over the 2015-2020 term, including Return on Equity and the proposed incentive sharing mechanism.
4. Appropriateness of continued pricing discretion for Interruptible Transportation and Short Term Firm Transportation services.
5. Appropriateness of TransCanada's proposed service modifications, including renewal provisions, contract terms, and conversion from long-haul to short-haul contracts.
6. Appropriateness of the proposed Bridging Contribution.
7. Appropriateness of the proposed framework for segmentation of the Mainline system post-2020, including information on cost allocation, asset values, and the future treatment of the Western Mainline under the proposed segmentation.

The hearing will not consider toll levels and tolling methodologies related to specific *National Energy Board Act* Part III facility applications currently or anticipated to be before the NEB. The hearing will also not consider issues associated with abandonment funding, specifically regarding hearings MH-001-2012 and MH-001-2013.